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RAPID RESPONSE R&D FOR THE PROPULSION DIRECTORATE

Delivery Order 0019: Advanced Alternative Energy Technologies, Subtask: Life Cycle Greenhouse Gas Analysis of Advanced Jet Propulsion Fuels: Fischer-Tropsch Based SPK-1 Case Study

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National Energy Technology Laboratory

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Final Report

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14. ABSTRACT

The purpose of this report is to provide a framework and guidance for estimating the life cycle greenhouse gas emissions for transportation fuels, specifically aviation fuels. The focus on aviation fuels was driven by the patterns of fuel use by the federal government. Policies such as those outlined in Section 526 of EISA 2007 cause federal agencies to institute enforceable guidelines for procuring low-carbon alternative fuels. Federal consumption of fuels is dominated by the Department of Defense and the Air Force consumes more fuel than any of the other military services or federal agencies (Defense Science Board 2008). Thus, aviation applications may become early adopters of low-carbon transportation fuels.

The US Air Force convened a working group of individuals from government agencies, universities, and companies actively engaged in assessing greenhouse gas emissions from transportation fuels, and requested that this group develop guidance on procedures for estimating greenhouse gas emissions in aviation applications, using currently available data and tools.

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1.0 EXECUTIVE SUMMARY

The United States is currently faced with multiple strategic objectives related to energy: supply security, economic sustainability, and concerns over global climate change. Use of liquid fuels for defense, transportation, and other purposes is at the crux of this dilemma: high fuel prices directly affect government and private sector operation costs; fuels usage results in significant carbon dioxide (CO_2) emissions; and reliance on foreign fuel sources exposes potential vulnerabilities in global supply chains needed for US operations. In accordance with the Energy Independence and Security Act (EISA) of 2007, the US Air Force is assessing various sources of alternative fuels, including bio-derived fuels, for use in support of military operations.

Environmental regulations have historically been focused on individual emission points, facilities, or industrial sectors. However, recent and emerging regulations for greenhouse gas (GHG) emissions, such as the EISA, have introduced the concept of product life cycle limits on emissions. Compliance with the EISA is of particular concern to the Air Force, and the Air Force has embarked on a program of testing non-petroleum based fuels in aircraft. These fuels, if used for purposes other than research and testing, would need to comply with EISA Section 526.

This case study assesses ten possible scenarios (also referred to as "pathways") of fuel production using Fischer-Tropsch (F-T) synthesis of coal and biomass using the *Framework and Guidance Document for Estimating Greenhouse Gas Footprints of Aviation Fuels* (hereafter, the Framework and Guidance Document) (Allen et al., 2010) developed by the Interagency Working Group (IAWG) for Alternative Aviation Fuels. The goals of this study were (1) to test the Framework and Guidance Document developed by the IAWG on a range of case study examples and (2) to provide detailed information on a set of life cycle scenarios for coal- and-biomass to liquid fuel production pathways. This document does not serve as a compliance determination of the alternatives evaluated for conformance with EISA Section 526. However, the information contained within and the insights from the results of the ten hypothetical scenarios provide a foundation for those interested in further exploring coal- and-biomass to jet fuel production alternatives for domestic energy security and environmental improvement.

For each of the ten scenarios tested, a life cycle inventory was developed to estimate the GHGs (carbon dioxide, methane, and nitrous oxide) associated with producing, transporting, storing, and using alternative or synthetic jet fuel for purchase by the US government, in comparison with the life cycle GHG emissions associated with conventional petroleum-based jet fuel. Specifically, this case study evaluates a coal and biomass to liquids (CBTL) system in which bituminous coal (Illinois No. 6) and biomass (switchgrass) serve as inputs to a gasification process with additional processing using a F-T catalyst, producing the following liquid fuel outputs: F-T jet fuel, F-T diesel, and F-T naphtha. The F-T jet fuel is blended with conventional petroleum-based jet fuel (blended in a 1:1 mixture by volume) to produce a saleable product.

Two carbon management strategies for handling captured carbon dioxide (CO_2) at the CBTL plant are considered within the study: storage in a saline aquifer and enhanced oil recovery operation (i.e., CO_2-EOR). Multiple allocation schemes are also explored and discussed within the report for determining the share of GHG emission associated with the production of the F-T jet fuel in contrast with the F-T diesel and F-T naphtha coproducts produced at the CBTL plant.

1.1 CBTL Case Study Scenarios and System Boundary

This study models the ten jet fuel production scenarios listed in Table 1. These scenarios should not be considered an exhaustive list of scenario configurations covering all aspects that are available for CBTL production selected for evaluation. Instead, they are simply ten distinct paths of production. Each scenario represents a single modeling pathway that a fuel producer might choose. As a result, this report contains documentation and results for each of the ten scenarios. In practice, an alternative jet fuel producer assessing the life cycle GHG footprint of their alternative using the Framework and Guidance document developed by the IAWG would only have one scenario. All variations in operating parameters and feedstock selection would be captured as a form of modeling and/or scenario uncertainty within the final results.

Table 1. Scenarios for Illinois No. 6 Coal and Biomass-to-Jet Fuel Pathways

Scenario	Coal and Biomass to Liquids (CBTL) 30,000 Barrel per Day (bbl/d) Plant Configuration				Carbon Management Strategy
	Illinois No. 6 Coal (% by wt.)	Switchgrass (% by wt.)	Type of F-T Catalyst	CBTL Jet Fuel Production (bbl/d)	
1	100%	0%	Iron	15,940	CO_2-EOR
2	85%	15%	Iron	15,940	CO_2-EOR
3	70%	30%	Iron	15,940	CO_2-EOR
4	87%	13%	Cobalt	17,370	CO_2-EOR
5	87%	13%	Cobalt	23,950	CO_2-EOR
6	100%	0%	Iron	15,940	Saline Aquifer
7	85%	15%	Iron	15,940	Saline Aquifer
8	70%	30%	Iron	15,940	Saline Aquifer
9	87%	13%	Cobalt	17,370	Saline Aquifer
10	87%	13%	Cobalt	23,950	Saline Aquifer

The system boundary considered for this study encompasses a 30-year timeframe, with processes and procedures included in the five LC stages shown in Figure 1. The materials system boundary includes all energy production, transport, conversion, and end use processes. Figure 1 also provides a summary of the materials system boundary illustrating all key processes within each life cycle stage (not all processes shown are applicable to all scenarios). The facilities included in the study system boundary are generally located in the US Midwest and South, including northern Missouri for the CBTL facility and switchgrass production, southern Illinois for coal production, and western Texas for CO_2 enhanced oil recovery.

The following GHGs are inventoried within this study: carbon dioxide (CO_2), methane (CH_4), and nitrogen dioxide (N_2O). The inventory of GHGs emitted to the atmosphere is done on both a mass (kilograms [kg]) basis and in terms of the 100-year global warming potential (GWP) of each gas as determined by current and previous Intergovernmental Panel on Climate Change (IPCC, 2007, 2001, 1996) reports. GWP is reported in mass of carbon dioxide equivalents (CO_2e). Other GHGs are considered insignificant in terms of relevance to this study, and therefore were not included.

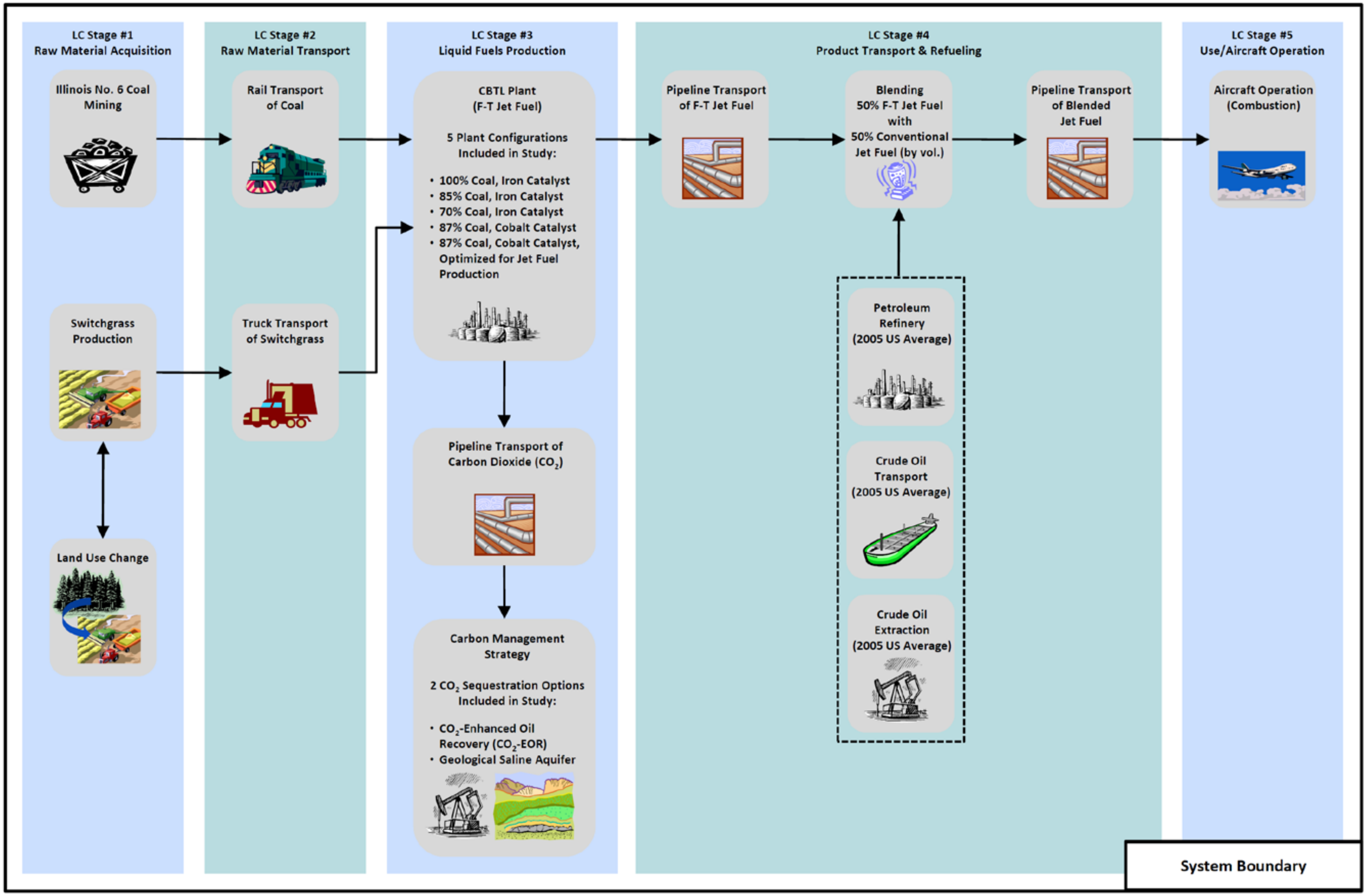

Figure 1. Baseline System Boundary with First Order Processes

1.2 CBTL Case Study Results

The results of this study allow direct comparison of life cycle GHG emissions from the production and use of F-T jet fuel with life cycle GHG emissions of jet fuel derived from petroleum. These comparisons require an objective basis, referred to as the functional unit, which reflects the function performed by the products investigated. The functional unit of this study is the quantity of jet fuel that is necessary to produce one million joules (MJ) lower heating value (LHV) of combustion energy to move a gas turbine engine that powers an aircraft.

Results from the study indicate that all scenarios except for Scenario 1 (0 percent switchgrass, iron catalyst, EOR) would result in life cycle GHG emissions that are below those of conventional jet fuel. Figure 2 summarizes the life cycle GHG results for each of the ten scenarios. The graph presents the probabilistic results in a "box and whisker" plot. In Figure 2, the bottom line of the box is the 25th percentile, the middle line is the median, and the top line of the box is the 75th percentile. The outlier bars (the "whiskers") show minimum and maximum. The "x" marker indicates the best estimate and the solid line is the CO_2e emissions for conventional jet fuel.

The results include two forms of coproduct allocation, energy and displacement, within the uncertainty of the results. The choice of coproduct allocation method was found to make a substantial difference in results. For Scenario 1 (0 percent switchgrass, iron catalyst, EOR), calculating results using displacement allocation causes total life cycle emissions to exceed life cycle emissions from conventional jet fuel. Calculating results using energy allocation results in life cycle emissions that are below conventional jet fuel emissions rates. Thus, according to the results of this study, the manner in which coproducts are allocated within the life cycle analysis can potentially inform the viability of a potential project. As stated above, both methods of allocation were performed and included within the probabilistic results shown in Figure 2 as outlined in the Framework and Guidance document.

Comparative analysis of the results demonstrate that higher percentages of biomass result in lower life cycle CO_2e emissions when using switchgrass procured in northern Missouri. They also demonstrate that the choice of carbon management strategy has an effect on the results. For example, in Figure 2, Scenarios 1-5 show the life cycle emissions for a carbon management strategy that includes EOR. Scenarios 6-10 are analogous to Scenarios 1-5, except that they show the life cycle emissions for a carbon management strategy that is based on CO_2 sequestration in a deep saline formation. Comparing analogous scenarios (e.g., Scenario 1 to Scenario 6, Scenario 2 to Scenario 7, etc.) shows consistently lower life cycle GHG emissions for those scenarios that include CO_2 sequestration as a carbon management strategy. However, what is not illustrated by comparing the life cycle GHG results is the quantity of additional domestic crude oil produced from the CO_2-EOR operation that is not obtained when storing CO_2 in a deep saline formation. The results show that for each 30,000 bbl/d CBTL plant, the storage of CO_2 using CO_2-EOR as a carbon management strategy produces an additional 60,000 bbl/d of domestic crude oil.

A detailed evaluation of the modeling parameters and data inputs identified the following to have the most significant influence on the study results: quantity of methane released to the atmosphere per ton of coal mined, the percentage of CO_2 captured by the CBTL plant, and the rate of N_2O emissions from nitrogen fertilizer applied to the switchgrass field. The effects of both coal and biomass acquisition choices have been demonstrated to add equivalent levels of uncertainty to the modeling results as plant configuration and operating choices.

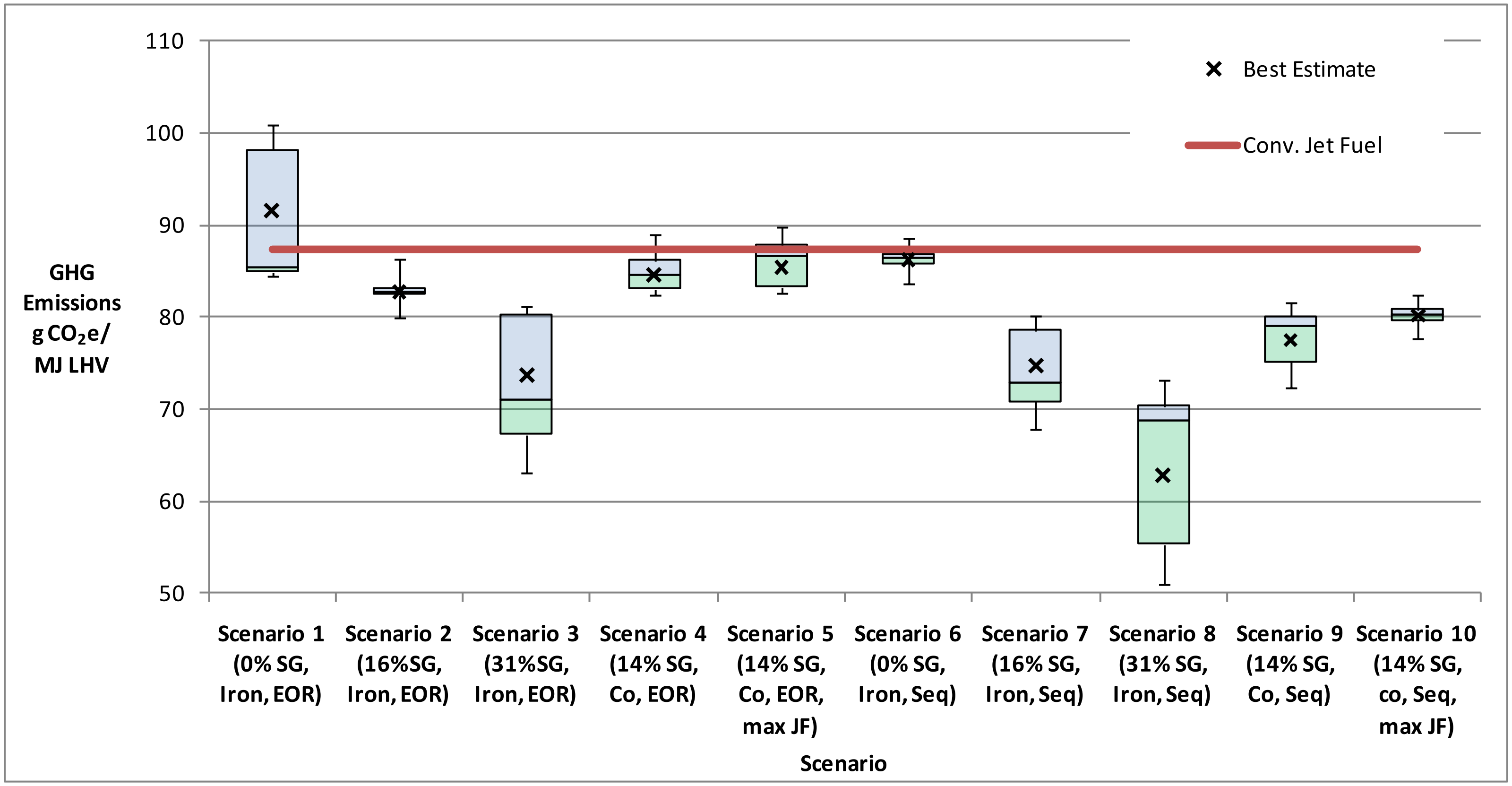

Figure 2. Uncertainty in CO_2e Emissions (Using IPCC 2007 GWP) for All Scenarios Using Combined Result

1.3 CBTL Case Study Limitations

In terms of broader study limitations, the model boundaries and modeling choices contained in the ten scenarios inform the following study limitations, which should be considered when interpreting final results and conclusions generated from this study (in no specific order):

- **Mine and Mine Methane Emissions:** This study presumes that Illinois No. 6 sub-bituminous coal from an underground longwall mine would be used, having an average methane emission rate of 150 scf CH_4/ton with 40 percent capture. Use of an alternative coal type, mine type, methane emission rate, or methane capture rate could increase or decrease mine and mine methane related GHG emissions.
- **Biomass Production:** This study presumes that farmed switchgrass would be used as the sole source of biomass. However, alternative sources of biomass could also have been chosen, such as farmed short rotation woody crops or corn stover, or biomass waste streams such as agricultural wastes or logging wastes. The use of alternative farming practices, crop requirements, and/or biomass source could increase or reduce life cycle GHG emissions.
- **Biomass Yields:** This study presumes that switchgrass production would yield 4.7 dry tons per acre per year of biomass. However, switchgrass yields reported in the literature are highly variable, in part reflecting farming practices and regional conditions. Higher or lower switchgrass yield values could substantially decrease or increase life cycle land use, respectively.
- **Biomass Transport:** This study presumes a 50-mile switchgrass production radius. The intensity of biomass transport emissions is expected to increase with increases in production radius. Therefore, substantial increases in the biomass production radius for this study could result in concurrent increases in transportation related GHG emissions, as well as increases in cost, which under some cases could render a longer distance biomass collection scheme infeasible.
- **CBTL Facility Carbon Capture Rate:** The rate of carbon capture at the F-T facility used for this study is 91 percent, which is expected to be a conservative estimate of actual carbon capture rates. However, carbon capture facilities have not been widely implemented at the commercial scale. Therefore, a higher or lower carbon capture rate may apply to some future studies. Increases or decreases in this rate would result in concurrent increases or decreases in life cycle GHG emissions.
- **CBTL Facility Modeling Scenarios:** In order to model the F-T facility, output from a separate ASPEN model was incorporated into the life cycle model used for this study. As a result, the F-T facility model included in this study is static: the workings of the F-T facility cannot be updated or altered to evaluate different F-T facility parameters and setups, without performing substantial additional analysis. The F-T facility results from this study represent specific assumptions and are not necessarily representative of all potential F-T facility designs.
- **EOR or Saline Sequestration Leakage Rates:** This study incorporates CO_2 leakage rates of less than one percent. However, actual leakage rates have not been extensively documented, and are expected to be difficult to monitor. Increases in CO_2 leakage rates could result in concurrent increases in life cycle GHG emissions.

- **Pre-Existence of Infrastructure:** Some of the infrastructure needed within the boundary of this study, such as a pipeline network suitable for transferring F-T Jet Fuel to the blending facility, was assumed to be pre-existing. No GHG emissions penalty was included for this infrastructure.
- **Comparative Study Results:** The purpose of this study is to provide a comparative evaluation of alternative fuels against baseline 2005 conventional petroleum jet fuel production and use. Results provided for this scenario reflect life cycle emissions from alternative jet fuel production in comparison to that baseline. However, results from this scenario are not intended to provide absolute GHG emissions values; results from this study should be used with caution, when comparing with life cycle analyses having different baseline assumptions and study goals.

1.4 CBTL Case Study Lessons Learned

One purpose of this case study was to test the LCA methods set forth in the Framework and Guidance Document. The following identifies several areas of potential improvement to be further investigated by the IAWG. Any recommended changes by the IAWG as a result of this case study effort, or other related case study efforts, would result in a revised *Framework and Guidance Document for Estimating Greenhouse Gas Footprints of Aviation Fuels*.

- Add guidance on documenting methodology limitations and uncertainty that cannot be quantitatively documented.
- Reduce the level of effort and/or approach required to document Data Quality Indicator scores.
- Clarify/restate in the Framework and Guidance Document's data quality section that high quality data (data that score a 1 or 2) should not use a default +/- 10 percent uncertainty bound when better or actual stochastic properties are known.
- Better define the scope of a "unit process" when applying the greater than 0.1 CO_2e/MJ limit to determine significance.
- Add guidance on reporting and interpreting study results.
- Consider recommending a preferred or default co-product allocation method for evaluating alternative jet fuel options.
- Reasonable levels of documentation and reporting should be evaluated for application of the Framework and Guidance Document.

2.0 INTRODUCTION

This section provides background information for this study, including basic definitions, an overview of life cycle stages and scenarios considered, methods, and key findings.

2.1 About This Study

The United States is currently faced with multiple strategic objectives related to energy: energy supply security, economic sustainability, and concerns over global climate change. Use of liquid fuels for defense, transportation, and other purposes is at the crux of this dilemma: high fuel prices directly affect government and private sector operation costs; the fuels used result in significant carbon dioxide (CO_2) emissions; and reliance on foreign fuel sources exposes potential vulnerabilities in global supply chains needed for US operations. In accordance with the Energy Independence and Security Act (EISA) of 2007, the US Air Force is assessing various sources of alternative fuels, including bio-derived fuels, for use in support of military operations.

Environmental regulations have historically been focused on individual emission points, facilities, or industrial sectors. Permit limits for individual stacks, facility-wide emission caps, and even sector-wide emission caps, with trading allowed among facilities, have become familiar parts of the regulatory landscape. However, some emerging regulations for greenhouse gases (GHG) have introduced the concept of product life cycle limits on emissions. In particular, the EISA, signed into law in the United States on December 19, 2007, placed restrictions on greenhouse gas emissions associated with the production, transport, and consumption of transportation fuels that are purchased by the US federal government. Specifically, Section 526 of EISA provides that:

> *No Federal agency shall enter into a contract for procurement of an alternative or synthetic fuel, including a fuel produced from nonconventional petroleum sources, for any mobility-related use, other than for research or testing, unless the contract specifies that the lifecycle greenhouse gas emissions associated with the production and combustion of the fuel supplied under the contract must, on an ongoing basis, be less than or equal to such emissions from the equivalent conventional fuel produced from conventional petroleum sources.*

Section 526 of EISA is just one example of this emerging class of life cycle regulation. Other federal regulations are in place, such as the Renewable Fuel Standard (RFS—see, for example, US EPA, 2009 a, 2009 b). States are also developing life cycle regulations (e.g., the California Low Carbon Fuel Standard [CARB], 2010) and international standards are emerging (British Standards Institute, 2008).

Compliance with EISA Section 526 is of particular concern to the Air Force. The Air Force has embarked on a program of testing non-petroleum based fuels in aircraft (see, for example, Corporan, et al., 2007), with a focus on blends of conventional petroleum with synthetic paraffinic kerosene (SPK) derived from Fischer-Tropsch (F-T) processes. Most analyses of F-T fuel GHG footprints have examined the use of F-T fuels as a replacement for diesel. However, new fuel specifications (US Air Force, 2008; US Department of Defense, 2008) now allow certain fractions of the F-T product range to serve as jet fuels. These fuels, if used for purposes other than research and testing, would need to comply with EISA Section 526.

To better understand the potential life cycle effects of the production and use of alternative fuels, as relevant to the Air Force, an Aviation Fuel Life Cycle Assessment Working Group (Working

Group) was assembled from members of US universities, national laboratories, government agencies, companies, and private research centers. The Working Group comprises specialists and experts in GHG emissions evaluation, biomass production, energy extraction, land use, advanced fuels production, enhanced oil recovery, carbon sequestration, and related fields. The Working Group developed the Air Force's *Framework and Guidance for Estimating Greenhouse Gas Footprints of Aviation Fuels* (i.e., the Framework and Guidance Document; Allen et al. 2009), and is now conducting a series of case study life cycle assessments (LCA) for alternative fuels production. This case study assesses ten possible scenarios for their compliance with EISA Section 526, and also tests the methods described in the Framework and Guidance Document as relevant to Air Force requirements.

Based on projected military use of liquid fuels, and the rising need for greater energy security through economically viable/environmentally attractive alternatives, the Working Group has evaluated the production of low sulfur jet fuel from coal and mixed coal and biomass feedstock sources. Preliminary economic and environmental studies have indicated these options to be economically and environmentally viable solutions to help meet the current US liquid fuels challenge (National Energy Technology Laboratory [NETL], 2007; NETL, 2009a). The purpose of this study is to estimate the life cycle GHGs associated with producing, transporting, storing, and using alternative or synthetic transportation fuels for purchase by the US government, for comparison with the life cycle GHG emissions associated with conventional petroleum.

The present case study evaluates a system in which coal and biomass serve as inputs to a gasification process with additional processing using the F-T process. The outputs from this process are the following liquid fuels: F-T jet fuel, F-T diesel, and F-T naphtha. The liquid fuel production facility is referred to as a coal- and biomass-to-liquids (CBTL) facility in this report. One benefit of the gasification process is that CO_2 is generated as a fairly concentrated stream that can readily be captured. This case study system includes the capture of CO_2, its compression to a supercritical state and, and transport of the supercritical CO_2 through a pipeline for one of two distinct CO_2 management strategies: (1) the use of CO_2 for enhanced oil recovery (EOR) in the Permian Basin in West Texas, where it is used to extract crude oil, natural gas and natural gas liquids (NGLs) from the subsurface; or (2) the permanent storage and sequestration of CO_2 in an appropriate deep saline aquifer.

This work leverages the expertise of the Working Group, which comprises academic and government researchers and research agencies. The participants of the Working Group are listed in Table 2. The participants were part of one or more subgroups, with the subgroups organized by the stage of the life cycle analysis. Data and model structures were provided by each of the subgroups, and were assembled into a single life cycle model for production of F-T jet fuels.

Table 2. Work Group Members and Contributors to this Study

Group Member	Institution
Coordination, Model Compilation, and Report Preparation	
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Steve Kennedy	AFRL
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Dong Gu Choi	Georgia Institute of Technology
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Daniel Baniszewski	Defense Logistics Agency
Amgad Elgowiny	Argonne National Laboratory
Michael Wang	Argonne National Laboratory
Jet Fuel End Use (LC Stage #5)	
Jim Hileman (Lead)	Massachusetts Institute of Technology
Kris Atkins	Boeing Corporation
Warren Gillette	Federal Aviation Administration
Bill Harrison	US Air Force

Note: Please see acronym list for full definitions

2.2 Study Background

The following discussion of background for the study includes generalized definitions and information on LCAs and GHGs, an overview of the lifecycle stages included in this study, a review of the ten scenarios considered, and a summary of the structure of this report.

2.2.1 Definition and Scope of Life Cycle Assessment

LCA is a modeling tool used to estimate and compare the environmental flows associated with the production of a product or service. The scope of a particular LCA may vary substantially based on its purpose. For instance, LCAs may be very broad in scope, considering a wide array of materials and energy inputs, alongside outputs of products, materials, and byproducts, such as air emissions, water emissions, solid wastes, and other relevant environmental flows. Alternatively, an LCA can be focused on an explicit set of inputs and/or emissions. These focused LCAs are typically used for evaluation of a particular process or set of emission categories, or to inform a specific decision making process. The present study is formed as a focused LCA that estimates GHG emissions from the production of alternative fuels, for the purpose of assessing compliance with the EISA and testing the methods described in the Framework and Guidance Document.

2.2.2 Greenhouse Gases

GHGs are atmospheric gases that trap heat radiated from the earth's surface inside the earth's atmosphere. They allow sunlight to enter the atmosphere, but reduce the rate at which heat can escape from the atmosphere. Atmospheric GHG concentrations have increased substantially since the industrial revolution. Global climate change is the gradual warming of the earth's atmosphere, land surface, and oceans, believed to be a result of increased GHG concentrations in the atmosphere. Many thousands of studies on GHGs and their effect on global climate change have been produced by academic, government, and private researchers worldwide.

On April 2, 2007, in *Massachusetts v. US EPA*, 549 US 497 (2007), the US Supreme Court found that GHGs are air pollutants under the federal Clean Air Act, giving the US EPA the authority to regulate GHG emissions. On May 13, 2010, the US EPA issued a final rule that

establishes an approach to addressing GHG emissions from stationary sources, under the Clean Air Act. The rule sets thresholds for GHG emissions that define when permits under the New Sources Review Prevention of Significant Deterioration, and Title V Operating Permit programs are required for new and existing industrial facilities. The final rule addresses emissions from a group of six GHGs:

1. Carbon dioxide (CO_2)
2. Methane (CH_4)
3. Nitrous oxide (N_2O)
4. Hydrofluorocarbons (HFCs)
5. Perfluorocarbons (PFCs)
6. Sulfur hexafluoride (SF_6)

The first three (bolded above) are the most important in terms of total global atmospheric forcing potential. While the remaining three chemical groups can have large forcing potentials on a per pound basis, negligible quantities are expected to be released in the production of alternative aviation fuels. For this reason, only the first three have been selected for consideration within the scope of this LCA.

2.2.3 Life Cycle Stages

The following briefly describes the life cycle (LC) stages evaluated in this case study. Detailed descriptions of environmental modeling assumptions applied to each of the LC stages, and the individual processes/building blocks for assessing each stage, are presented in **Sections 4 to 8** of this document.

Figure 3 shows a conceptual representation of the process flows (and system boundaries) for the model components included in the system boundary. The activities within the system boundary have been allocated into the following LC stages to represent the key processes across each pathway.

2.2.3.1 Life Cycle Stage #1: Raw Material Acquisition

LC Stage #1a: Illinois No. 6 Coal Extraction. The LC Stage #1a boundary starts with the acquisition of Illinois No. 6 coal from an underground mine via a longwall mining process. The coal is transported to the surface, cleaned (i.e., coal is separated from inorganic rock), and stockpiled. The boundary ends with the loading of Illinois No. 6 coal onto a train for transport under LC Stage #2a.

LC Stage #1b: Switchgrass Biomass Production. The LC Stage #1b boundary starts with the preparation of land in support of the agricultural production of switchgrass. The switchgrass is seeded, cultivated, harvested, and processed into either rectangular or round bales and stored at the farm until transport. The boundary ends with the loading of the bales of switchgrass onto trucks for transport under LC Stage #2b.

LC Stage #1c: Direct and Indirect Land Use. The LC Stage #1c boundary includes GHG emissions associated with land use change as a result of switchgrass production. The land use analysis includes direct land use effects and indirect land use effects. Direct land use effects are changes in GHG emissions associated with converting a specific parcel of land from one use

(such as growing row crops or pasture crops) to another use (switchgrass production). Indirect land use effects arise when the new land use (switchgrass production) displaces land used for necessary agricultural activities (such as growing food crops). To make up for the displaced crops, other land not currently used for agricultural production must be converted to agricultural use to grow the displaced crops. The indirect land use analysis evaluates how changing land area from non-agricultural to agricultural use changes GHG emissions. While land use changes can occur at any LC stage, growing switchgrass results in the largest changes in land use, by far, of all stages. This is because switchgrass production requires far more land area than any other LC stage. The land use changes associated with each stage are discussed in **Section 4.3** of this report, demonstrating that switchgrass production results in the largest land use change. The boundary for LC Stage #1c is consistent with LC Stage #1b.

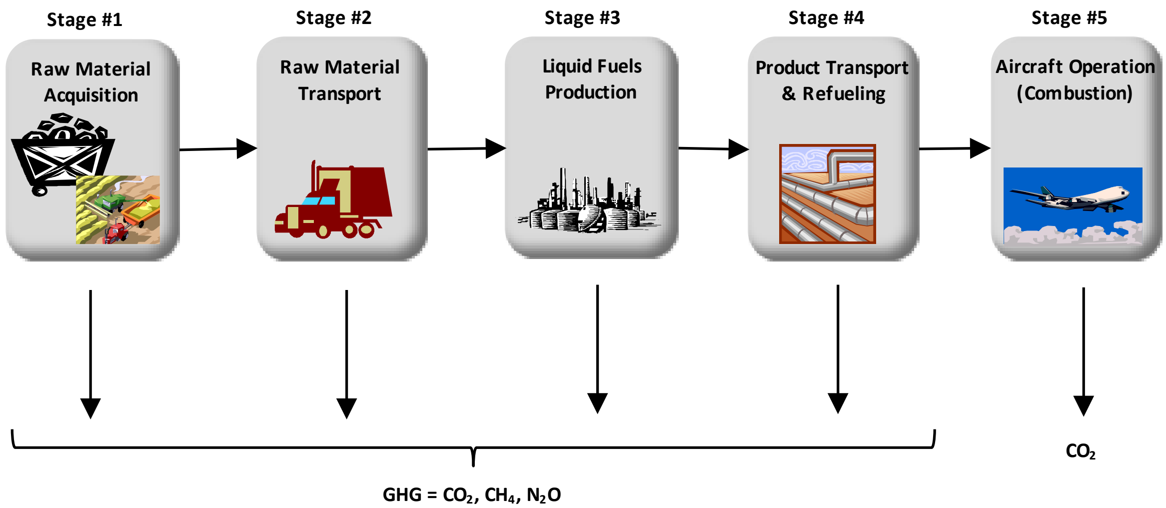

Figure 3. System Boundary for Coal and Biomass to Liquid Jet Fuel Life Cycle GHG Analysis

2.2.3.2 Life Cycle Stage #2: Raw Material Transport

LC Stage #2a: Coal Transport. LC Stage #2a includes the rail transport of Illinois No. 6 coal, via train, from the coal mine to the CBTL facility under LC Stage #3a. The boundary ends with unloading of the Illinois No. 6 coal at the CBTL facility.

LC Stage #2b: Switchgrass Transport. LC Stage #2b includes truck transport of switchgrass from the biomass production/storage area to the CBTL facility under LC Stage #3a. Rectangular and round bales of switchgrass are both transported via truck. The boundary for this LC stage ends with unloading of the biomass at the CBTL facility.

2.2.3.3 Life Cycle Stage #3: Liquid Fuels Production and Carbon Dioxide Management

LC Stage #3a: CBTL Facility. The LC Stage #3a boundary begins with the receipt of feedstock material (coal and switchgrass) at the entrance to the CBTL facility and ends at the entrance to various pipelines. The liquid fuels generated at the CBTL facility are jet fuel (synthetic paraffinic kerosene), diesel, and naphtha using the F-T process. To distinguish these fuels from their petroleum-derived (i.e., conventional) counterparts, they are referred to as F-T jet fuel, F-T diesel, and F-T naphtha in this report. The F-T jet fuel is assumed to be transported via a pipeline to a petroleum refinery, where it would be blended with conventional jet fuel.

This stage also includes the capture of CO_2 at the CBTL facility and compression of this CO_2 to a supercritical state. The supercritical CO_2 is transported from the CBTL facility through another pipeline under either (1) Stage #3b to an EOR operation, or under (2) Stage #3d to a sequestration site for injection and storage in a saline aquifer.

To summarize, the LC Stage #3a boundary starts at the entrance of the CBTL facility with the receipt of coal and switchgrass and ends at the entrance to two pipelines: (1) a petroleum pipeline used to transport F-T jet fuel under LC Stage #4 to a petroleum refinery for mixing with conventional jet fuel, and (2) a CO_2 pipeline used to transport supercritical CO_2 to either EOR operations (LC Stage #3b) or a sequestration site (LC Stage #3d).

LC Stage #3b: Supercritical CO_2 Transport. The LC Stage #3b boundary starts at the CO_2 pipeline, which transports CO_2 from the CBTL facility 775 miles by pipeline to an oil field in the Permian Basin of western Texas. The boundary ends at the EOR facility.

LC Stage #3c: Enhanced Oil Recovery. The LC Stage #3c boundary starts at the end of the supercritical CO_2 pipeline and ends at the entrance to petroleum pipelines, which transport petroleum products extracted at the EOR facility, for further processing. The EOR operations are assumed to be located in the Permian Basin of western Texas. EOR is implemented after primary and secondary oil recovery techniques have extracted as much oil as possible. For the EOR process considered here, supercritical CO_2 is injected into the ground, along with water, to extract additional petroleum products from the subsurface. The primary products generated by EOR are crude oil, natural gas, and natural gas liquids. Natural gas is used as an energy source within the EOR operations, so some (even all) of the extracted natural gas may be used by the EOR operations. At the conclusion of EOR operations, the injected CO_2 remains in the subsurface, effectively sequestering the CO_2.

LC Stage #3d: Supercritical CO_2 Sequestration. The LC Stage #3d boundary starts at the CBTL facility, at the entrance to the CO_2 pipeline, and ends at a saline aquifer. In between, the CO_2 is transported through the pipeline and injected into the aquifer for permanent storage. CO_2 transport along the pipeline for LC Stage #3d is modeled the same as for LC Stage #3b, except that for LC Stage #3d, the transport distance is assumed to be 100 miles, rather than the 775 miles assumed for LC Stage #3b.

2.2.3.4 Life Cycle Stage #4: Product Transport and Refueling

LC Stage #4a: Transport to Refinery and Blending. The LC Stage #4a boundary starts at a pipeline meant to carry finished jet fuel from the CBTL facility. The pipeline connects the CBTL facility to a petroleum refinery located in Wood River, Illinois, and includes emissions associated with energy requirements for pipeline transport. At the refinery, the F-T jet fuel is blended in a 1:1 mixture with conventional petroleum jet fuel. Emissions resulting from blending operation are considered, and the LC Stage #4a boundary ends at the start of a pipeline used for transport of blended jet fuel, under LC Stage #4c.

LC Stage #4b: Upstream Emissions of Conventional Jet Fuel. LC Stage #4b serves as an accounting device, in order to incorporate upstream GHG emissions associated with conventional jet fuel production and delivery to the blending facility. Included are emissions from crude oil extraction, transport, and refining. The LC Stages #4b boundary begins and ends at the point of blending, under LC Stage #4a, thereby incorporating upstream conventional jet fuel emissions into LC Stage #4.

LC Stage #4c: Transport of Blended Jet Fuel. The LC Stage #4c boundary begins at a pipeline that transports blended jet fuel away from the blending facility, under LC Stage #4a. From that point, two options are considered for the final disposition of the blended jet fuel. Under Option 1, all the blended jet fuel is transported via pipeline from the refinery in Wood River to Chicago's O'Hare airport. Under Option 2, all the blended jet fuel is transported by pipeline to a terminal facility for temporary storage in a tank. From the tank, 60 percent of the blended jet fuel is transported by pipeline to Chicago O'Hare Airport and the remaining 40 percent is transported by tanker truck to regional airports. The boundary of LC Stage #4c ends at the point where the blended jet fuel enters the aircraft.

2.2.3.5 Life Cycle #5: Use/Aircraft Operation (Combustion)

LC Stage #5: F-T Jet Fuel Use. The LC Stage #5 boundary starts with the blended F-T jet fuel in the aircraft and ends with combustion of the fuel. This stage includes GHG emissions associated with blended jet fuel combustion.

2.2.4 Scenarios Considered

This study models the 10 jet fuel production scenarios listed in Table 4. For the purpose of this case study, the scenarios should not be considered uncertain parametric modeling choices, but 10 distinct paths of production, among a much broader range of possible production pathways. The intent herein was to conduct a thorough examination of a small range of fuel production options, not to represent all possible fuel production options. Each scenario represents a single modeling pathway that a fuel producer might choose. These scenarios were identified by Working Group members as being important variations to consider for the modeling of this study, and for testing the methods described in the Framework and Guidance Document. During the modeling process, these scenarios were incorporated into the F-T Jet Fuel Spreadsheet Model (for additional discussion of the F-T Jet Fuel Spreadsheet Model, refer to **Section 3.2.6**), as user-selectable options. Results were generated by selecting a single scenario from each LC stage, as relevant, and results from the various scenarios are discussed in **Section 10**. The scenarios reflect five different operating configurations for the CBTL (LC Stage #3a) and two different methods for managing the CO_2 captured by the CBTL process (LC Stages #3b, #3c, and #3d).

Table 4. Scenarios for Illinois No. 6 Coal and Biomass-to-Jet Fuel Pathways

Scenario	Coal and Biomass to Liquids (CBTL) 30,000 Barrel per Day (bbl/d) Plant Configuration				Carbon Management Strategy
	Illinois No. 6 Coal (% by wt.)	Switchgrass (% by wt.)	Type of F-T Catalyst	CBTL Jet Fuel Production (bbl/d)	
1	100%	0%	Iron	15,940	CO_2-EOR
2	84%	16%	Iron	15,940	CO_2-EOR
3	69%	31%	Iron	15,940	CO_2-EOR
4	86%	14%	Cobalt	17,360	CO_2-EOR
5	86%	14%	Cobalt	23,600	CO_2-EOR
6	100%	0%	Iron	15,940	Saline Aquifer
7	84%	16%	Iron	15,940	Saline Aquifer
8	69%	31%	Iron	15,940	Saline Aquifer
9	86%	14%	Cobalt	17,370	Saline Aquifer
10	86%	14%	Cobalt	23,950	Saline Aquifer

2.2.6 Methods

The methodology in the Framework and Guidance Document was utilized for this case study LCA and, as discussed previously, one purpose of this case study is to test the efficacy of the methods described therein. As discussed in greater detail in the Framework and Guidance Document, this methodology is in compliance with Section 526 of the EISA of 2007, and the International Organization for Standardization (ISO) 14044: 2006(E) (2006b), which requires the goal and scope of a study to be clearly defined and consistent with the level of detail and intended use of the study results, and specifies procedural standards and reporting methodologies for the LCA. For additional background on the LCA methodology used in this study, please refer to the Framework and Guidance Document.

2.3 Report Structure

This report describes the scope of this study, followed by several sections detailing modeled information for each life cycle stage, a presentation of results, critical analysis of results, and a discussion of conclusions and recommendations. The report is structured as follows:

Section 1: Executive Summary

Section 2: Introduction

Section 3: Study Scope

Section 4: Life Cycle Stage #1: Raw Material Acquisition

Section 5: Life Cycle Stage #2: Raw Material Transport

Section 6: Life Cycle Stage #3: Liquid Fuels Production

Section 7: Life Cycle Stage #4: Product Transport and Refueling

Section 8: Life Cycle Stage #5: Use/Aircraft Operation

Section 9: Co-Product Allocation Procedure

Section 10: Life Cycle GHG Results

Section 11: Discussion and Conclusions

Section 12: Case Study Assessment and Recommendations

Section 13: References

Appendix A: Calculating the F-T Jet Fuel Product Portion from an Iron Catalyst CBTL Process

Appendix B: Energy Content and Combustion Emissions of F-T CBTL Fuels

Appendix C: Lifecycle Emissions Results for the Modified Baseline System Boundary

3.0 STUDY SCOPE

This section provides an overview of the study scope, including goals, modeling approach, data quality approach, and interpretation procedures for life cycle stage results.

3.1 Goal

The objective of this effort is to evaluate and compare the life cycle GHG emissions of F-T jet fuel made from Illinois No. 6 coal and switchgrass to the life cycle GHG emissions of jet fuel made from petroleum. A common system boundary and consistent modeling assumptions are applied to all stages as described within this document.

3.2 Modeling Approach

The following discussion of modeling approach reviews modeling assumptions and procedures related to choice of the functional unit, system boundaries, secondary materials and energy inputs, allocation procedures, life cycle inventory metrics, modeling tools and procedure, and a summary of key modeling choices.

3.2.1 Functional Unit

The results of this study allow direct comparison of life cycle GHG emissions from the production and use of F-T jet fuel with life cycle GHG emissions of jet fuel derived from petroleum. These comparisons require an objective basis, referred to as the functional unit, which reflects the function performed by the products investigated. The functional unit of this study is the quantity of jet fuel that is necessary to produce one MJ lower heating value (LHV) of combustion energy to move a gas turbine engine that powers an aircraft.

The functional unit is distinguished from the primary reference flow designations for individual LC stages within the life cycle inventory (LCI). For example, the reference flow for LC Stage #3a (CBTL facility) is based on the production capacity of jet fuel, measured as the total kilograms of F-T jet fuel produced by the CBTL facility. Therefore, the reference flow for LC Stage #3a depends on which of the stage's five operational scenarios is assumed to be applicable for the CBTL. The functional unit is essentially the reference flow for the entire system (LC Stages #1 through #5). The results for each stage are converted at the system level (see **Section 10**), from the stage reference flow to the functional unit. This enables stage-level results to be combined and compared.

3.2.2 System Boundary

The system boundary is considered in terms of its geographic, temporal, and material extents, which are discussed in the following text.

3.2.2.1 Geographic System Boundary

A hypothetical location for placement of the CBTL facility was selected in Northern Missouri due to proximity to existing infrastructure and feedstock supplies. Switchgrass land availability and the distance to existing infrastructure were determined through use of the Biomass Availability Module under development at NETL (NETL, 2010a). Placement of the facility was based on switchgrass supply within a 50-mile radius to rail lines traveling from the Galatia Mine (regional proxy for surrounding mines) in Southern Illinois, and proximity to a major pipeline for shipping F-T jet fuel to a refinery in Wood River, Illinois (near St. Louis, Missouri) for blending and final transport of the blended jet fuel to O'Hare Airport in the Chicago area, as shown in

Figure 4. The electricity grid regions used in the study therefore vary based on LC stage, according to the location of the various facilities. Table 5 summarizes the electricity grid regions included in the study.

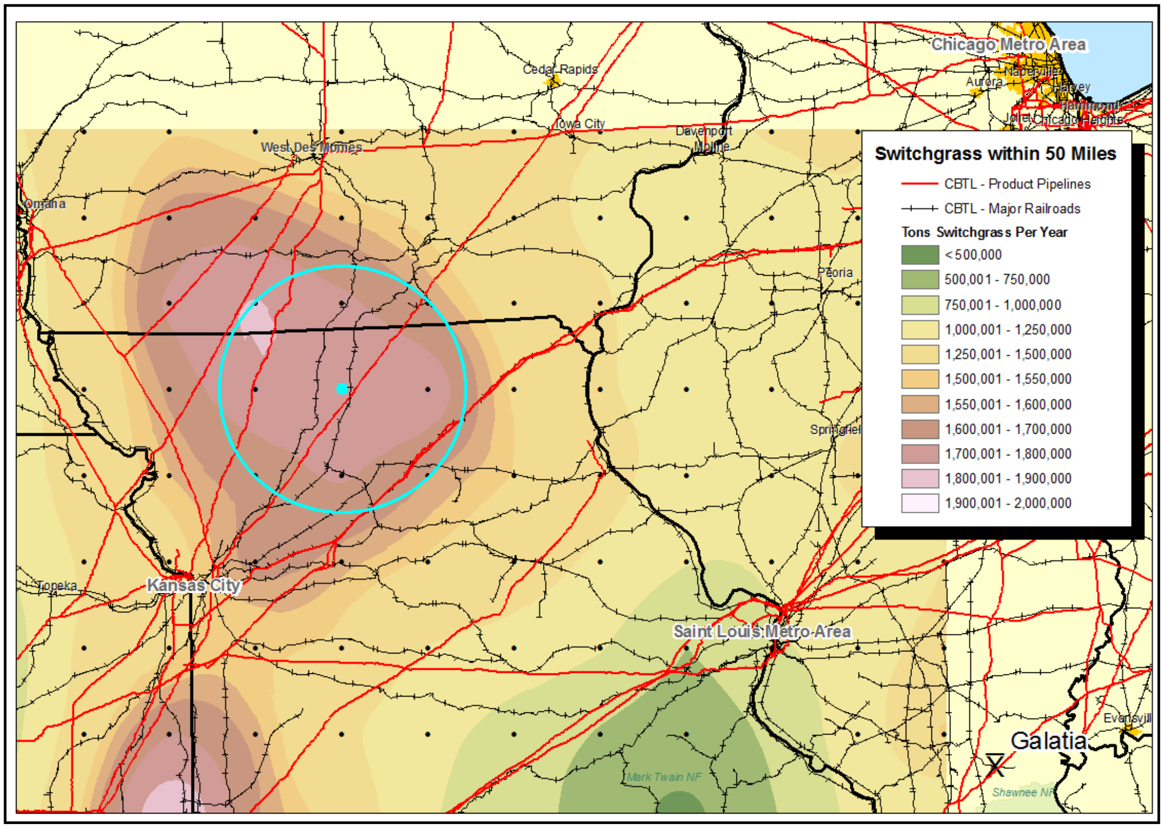

Figure 4. Hypothetical Facility Location and 50 Mile Switchgrass Production Radius (NETL, 2010a)

Table 5. Power Grid Regions for Each LC Stage

LC Stage	Power Grid Region
Stage 1a: Illinois No. 6 Coal Extraction	SERC
Stage 1b: Switchgrass Production	SERC and MRO
Stage 3a: Coal and Biomass to Liquids Facility	SERC
Stage 3b: Supercritical Carbon Dioxide Transport	SERC
Stage 3c: Enhanced Oil Recovery	ERCOT
Stage 4: Jet Fuel Transport, Blending, and Delivery	SERC

Note: Please see acronym list for full definitions

3.2.2.2 Temporal System Boundary

The environmental profiles were developed for a 30-year operating time period, referred to as the study period. The base year for the study is flexible, based on the data and modeling choices represented in the LCI model. However, the data incorporated into the F-T Jet Fuel Spreadsheet Model are intended to reflect current technology as of 2010. Use of the CBTL facility is assumed to start in 2012. The study also includes modeling of a hypothetical 3-year construction period, during which all facilities would be built and installed. All processes are considered to be in full operation on Day 1 following the construction period.

3.2.2.3 Material System Boundary

The material system boundary for this study includes processes and procedures included in five LC stages, as described in **Section 2.2.3** and in **Sections 4 to 8**. The materials system boundary includes all energy production, transport, conversion, and end use processes that are included in the study, including coal and switchgrass production and transport, energy conversion at the CBTL facility, carbon dioxide capture and transport, carbon dioxide sequestration or enhanced oil recovery, blending of F-T jet fuel with conventional jet fuel, life cycle emissions for production of conventional jet fuel, transport of blended jet fuels, and combustion of blended jet fuel in a jet engine. A high level view of the material system boundary was discussed in Figure 3.

Chapter 4.0 of the Framework and Guidance Document discusses the procedure for defining the system boundary for the study. The guidance recommends the following approach:

- Eliminate the use of subjective cut-off criteria
- Create reasonable data collection burdens in support of the current fuel polices, including a quantification of the on-going unit process operations within the primary production pathway chain
- Extend the boundaries as close to elementary flows at the system boundary as possible (identified by the ISO [14044] standard as the ideal)
- Target data collection efforts towards what is needed for understanding and estimating significant impacts contributors

Figure 5 depicts the first order processes (also referred to as the primary production chain) for the baseline material system boundary for the study. Second order material boundaries for each life cycle stage are described in **Sections 4 to 8**. Secondary flows within the F-T Jet Fuel Spreadsheet Model were evaluated based on a combination of peer reviewed documentation of available life cycle processes and EIOLCA[1] lifecycle data for the economic sector of the higher order flow within this study. The goals of creating reasonable data collection burdens, extending the boundaries as close to elementary flows, and targeting data collection efforts towards significant impact contributors were applied when defining the material boundary for each life cycle stage.

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[1] Economic Input-Output Life Cycle Assessment (EIOLCA) is a method for estimating the environmental inputs and emissions resulting from activities in the economy, based on a method developed by Nobel Prize economist, Wassily Leontief. Carnegie Mellon University maintains EIOLCA data and associated tools, available at http://www.eiolca.net/.

In defining the material system boundary for this study, three plausible boundaries were identified for Scenarios 1-5 that employ CO_2-EOR as a carbon management strategy. Two possibilities for the boundary arise from the observation that CO_2-EOR generates crude oil, and that a portion of this crude oil could be processed into conventional jet fuel. One choice for the boundary makes no assumption about what happens to the crude oil and the boundary ends at the production of crude oil and natural gas liquids by CO_2-EOR. This is referred to as the "Baseline System Boundary." The co-products exiting the Baseline System Boundary are F-T jet fuel, F-T diesel, F-T naphtha, crude oil and natural gas liquids. All co-products are energy products, which, as discussed later, facilitate allocation of GHG emissions.

The second choice for the boundary assumes that the crude oil produced by CO_2-EOR is processed to generate conventional jet fuel. In this situation, the boundary is extended to include transport of the crude oil to a petroleum refinery, processing of the crude oil into conventional jet fuel, and transport of the conventional jet fuel to an aircraft fuel tank. The boundary ends with the combustion of the jet fuel in an aircraft. This second material system boundary is defined in this study as the "Expanded System Boundary." After additional evaluation, it was determined that using the Expanded System Boundary added insurmountable complications to the allocation of GHG emissions to co-products and, consequently, the Expanded System Boundary was not pursued further in this study.

The third choice for the boundary cuts off the material boundary where supercritical CO_2 enters the EOR facility. This is referred to as the "Modified Baseline System Boundary." The GHG emissions associated with EOR are eliminated from the evaluation with this choice of system boundary. The co-products exiting the Modified Baseline System Boundary are F-T jet fuel, F-T diesel, F-T naphtha, and supercritical CO_2. Unfortunately, supercritical CO_2 is a very different product than the three F-T co-products and this complicates allocation of GHG emissions, as is discussed later.

The Baseline System Boundary is considered the most appropriate for this study. This system boundary eliminates supercritical CO_2 as a co-product and generates a suite of co-products that are all energy products, which facilitates allocation of GHG emissions. The results presented in **Section 10** utilize the Baseline System Boundary. The Modified Baseline System Boundary is considered a plausible system boundary, but is less appropriate than the Baseline System Boundary because disposition of the captured CO_2 is defined by the scenarios modeled as being sequestered in the CO_2-EOR operation. If the disposition of the captured CO_2 was unknown, or could not be specified by the CBTL facility (e.g., CO_2 was sold into an open market) then the Modified Baseline System Boundary would have been the preferred choice. To provide additional information on this alternative system boundary approach and its effect on GHG results, the Modified Baseline System Boundary was retained and presented in **Appendix C** for discussion purposes.

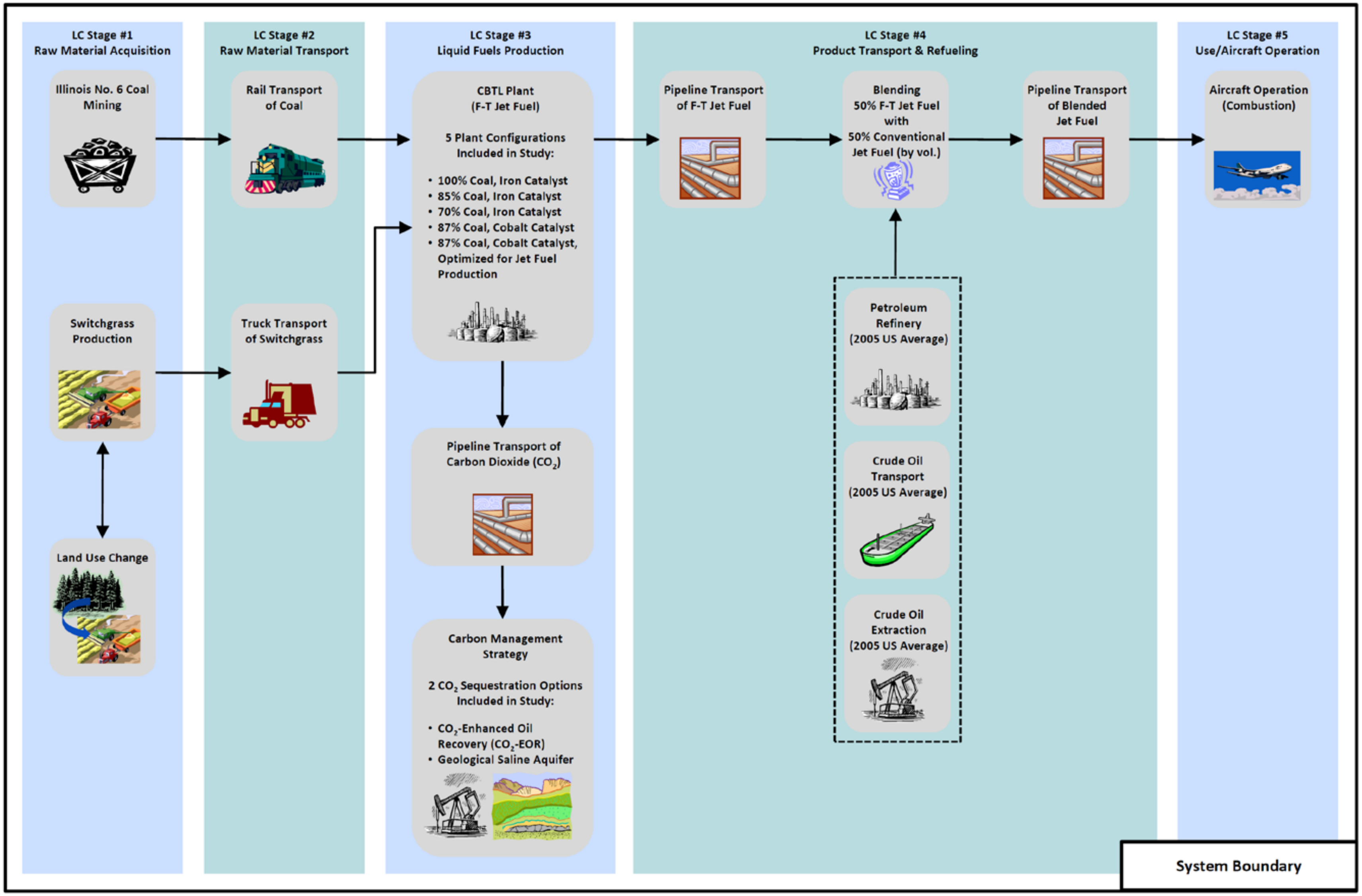


Figure 5. Baseline System Boundary with First Order Processes

3.2.2.4 System Boundary Limitations

This study considers GHG emissions associated with the production and use of F-T jet fuel from mixed coal-biomass feedstocks. The study also includes GHG emissions associated with the production and use of conventional jet fuels, which are blended with the F-T jet fuel. The study includes the secondary GHG emissions of energy and materials that are utilized in the various production processes, as discussed below.

The following secondary process functions are excluded from the study due to their low predictability:

- Humans involved in the system boundary have a burden on the environment as part of an overall LC, such as worker commuting and production of food for their consumption. However, inclusion of these secondary processes in the LC would require data collection beyond the significance threshold for this study as well as complicated procedures for allocation of human-related flows to fuel production. Further human impacts that are appropriately addressed through policy and value-based decisions, such as the societal impacts of humans in the workforce, are outside the scope of this study.
- Low-frequency, high-magnitude environmental events (e.g., routine/fugitive/accidental releases) are not included in the system boundaries, since such circumstances are difficult to associate with a particular product. More frequent, but perhaps lower magnitude events, such as material loss during transport, are included in the system boundary.
- Construction emissions are excluded for existing infrastructure that would not need to be replaced in the study period. Existing infrastructure is defined as meeting both of the following requirements: (1) infrastructure in existence on the start date of the study (January 1, 2012); (2) infrastructure with expected lifetime in excess of the length of the study period (30 years).

3.2.3 Secondary Material and Energy Inputs

Assessing the environmental LC perspective of each scenario also requires, at least in theory, that all significant material and energy resources be tracked back to the point of extraction from the earth (commonly referred to as the "cradle" in LCA terminology). In this evaluation, each stage (except Stage #1c land use change) is characterized by two unit processes, one for operations and one for construction. These unit processes list the principal material and energy input flows, the product and co-product output flows and the GHG emissions that occur in that unit process. For example, if diesel fuel is used in a unit process, the GHG emissions from combusting that diesel fuel are calculated in that unit process. The input flows to these operation and construction unit processes are typically not resources extracted from the earth, but material or energy products that have been processed or refined from resources extracted from the earth. In the previous example, diesel fuel is a product that has been refined from crude oil, which is a resource extracted from the earth. Thus, the operation and construction unit processes list the processed or refined inputs necessary for the unit process and estimate the GHG emissions directly generated within the system boundary of the unit process.

In order to account for resources and emissions associated with the production of the input flows, a secondary unit process is needed for each input flow that lists, in theory, the resources and GHG emissions associated with producing this input. Because the focus of this evaluation is on GHG emissions, the secondary unit processes developed for this evaluation provide cradle to

gate GHG emissions for each input flow, but they typically do not provide the energy and material resource inputs needed to produce the refined input.

Stage #1c, land use change, involves the influence of changing land from one use (such as pasture land) to another (such as switchgrass production) on GHG emissions. Stage #1c is different than all other stages in that it does not involve extraction, transport, production or use of material or energy. As such, this stage does not have operations and construction unit processes and it does not have inputs that require secondary unit processes. Stage #1c is discussed in more detail in **Section 3.2.6**.

3.2.4 Uncertainty

The Framework and Guidance Document lists three types of uncertainty in a life cycle assessment:

1. Data Uncertainty
2. Modeling Uncertainty
3. Scenario Uncertainty

All three types of uncertainty are addressed within this case study.

3.2.4.1 Data Uncertainty

Data uncertainty is discussed and assessed for LC Stage #1 (Raw Material Acquisition) through LC Stage #4 (Product Transport and Refueling) in the "Data Quality Assessment" sections of **Sections 4 to 8**. In accordance with the Framework and Guidance Document, LC Stage #5 (Use/Aircraft Operation) is defined as having no uncertainty and GHG emissions are reported only as a deterministic result.

The results of the data uncertainty analysis are carried forward and applied when considering both modeling and scenario uncertainty. In practice, both modeling and scenario uncertainty were iteratively considered while refining the life cycle inventory data needs for significance in accordance with the Framework and Guidance Document. The handling of data uncertainty for LC Stages #1-4 was determined based on the significance of the unit process to the life cycle results and the quality of the data as determined with the data quality indicator scores.

3.2.4.2 Modeling and Scenario Uncertainty

Model uncertainty is classified within the Framework and Guidance Document as any modeling choice that could not be adequately supported by data (i.e., professional judgment was required to determine the modeling choice). There are three sources of modeling uncertainty within this study: (1) unit process parameters (e.g., coal transport distance between the mine and the CBTL facility), (2) system boundary, and (3) co-product allocation. The latter two are both forms of LCA modeling uncertainty that result from multiple options for how to conduct the life cycle assessment. The first source is specific to uncertainties in parameters used to model the life cycle. Uncertainty in unit process parameters is managed in the same manner as data uncertainty. In some contexts, it is difficult to ascertain the difference between data uncertainty and unit process parameter (model) uncertainty. Within this study, unit process parameter uncertainty has been included with data uncertainty for each life cycle stage and listed as key variables, as described in greater detail in **Sections 4 to 8**. However, it should be noted that for

this study, an analysis of different allocation methods is necessary because more than one product is generated as a model output.

LCA modeling uncertainty, with the exception of unit process parameter modeling uncertainty, cannot be managed in the same manner as data uncertainty. LCA modeling options are parametric choices and are handled in the same manner as scenario uncertainty. Each modeling option requires the F-T Jet Fuel Spreadsheet Model to be run separately, resulting in unique sets of results, inclusive of data and unit process parameter modeling uncertainty. The results of multiple LCA modeling options are combined for each scenario to determine the bounds of the uncertainty range. This process is repeated for inclusion of scenario uncertainty.

As discussed previously, LCA modeling uncertainty exists within this study for both the selection of the system boundary and the choice of how to allocate between co-products produced within the system boundary. Table 6 summarizes the types of LCA modeling uncertainty assessed within this study. The system boundary and allocation methods are discussed in more detail in the next section.

Table 6. LCA Modeling Uncertainty Options Included in the Study

Source of Modeling Uncertainty	Modeling Options
System Boundary	1. Baseline System Boundary 2. Modified Baseline System Boundary
Co-Product Allocation	1. Energy Allocation 2. System Expansion/Displacement Model

3.2.5 Allocation Methods

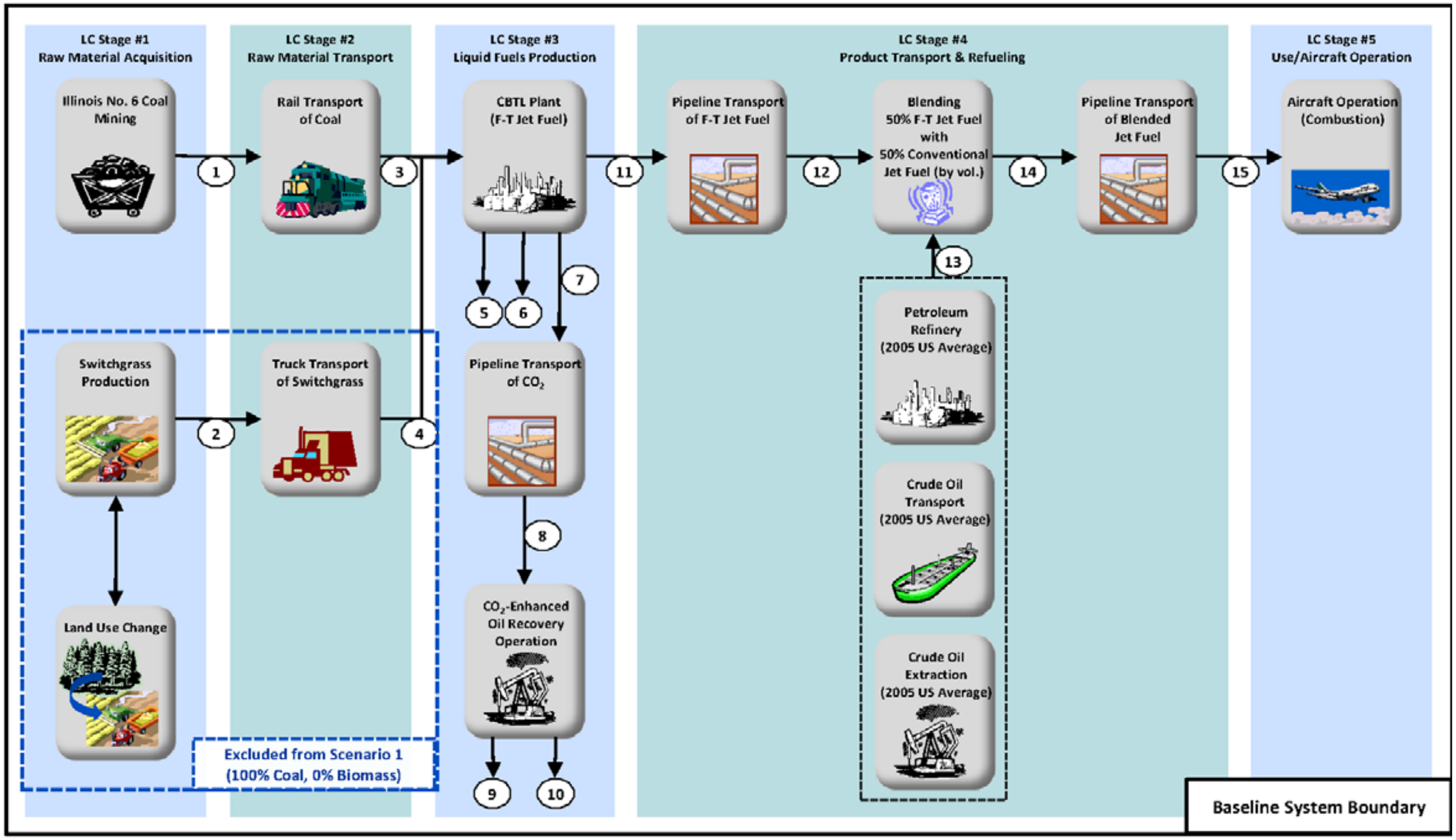
The allocation of GHG emissions to various co-products is an important part of any LCA. Allocation depends on the choice of system boundary, which in turn defines the co-products produced. The choice of system boundary and allocation method is discussed in more detail below.

3.2.5.1 System Boundary

Scenarios 1-5 use CO_2-EOR as a carbon management option. CO_2-EOR operation produces domestic crude oil and natural gas liquids as products within the system boundary. The disposition of crude oil produced by CO_2-EOR operation is assumed to be outside the control of the entity that is operating the CBTL facility and that is conducting the life cycle GHG analysis to determine the comparative carbon footprint of the alternative jet fuel to conventional jet fuel. Under the baseline system boundary, Scenarios 1-5 produce crude oil and natural gas liquids from the CO_2-EOR operation and list each as a co-product produced from the system boundary. The baseline system boundary for Scenarios 1-5 is presented in Figure 6 and for Scenarios 6-10 (wherein saline aquifer sequestration is considered for carbon management in lieu of CO_2-EOR) in Figure 7.

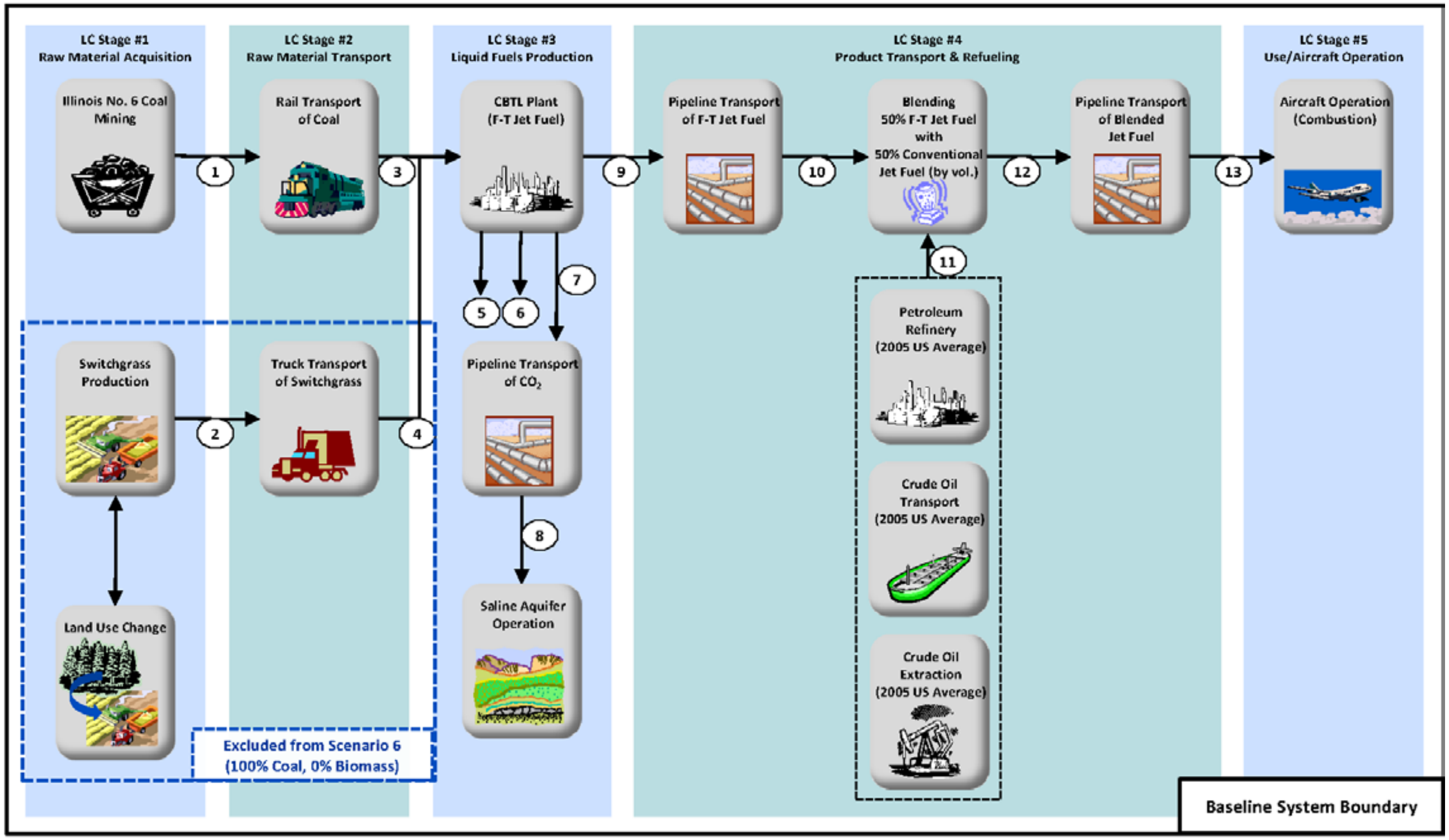
In the modified baseline system boundary, the system is cut off at the point where the supercritical CO_2 enters the EOR facility. This system boundary eliminates GHG emissions from CO_2-EOR, but leaves supercritical CO_2 as a co-product. As discussed previously, supercritical CO_2 is a very different co-product than the F-T co-products generated by the CBTL facility, and this complicates the allocation of GHG emissions. For example, if GHG emissions

are allocated on the basis of the energy content of the co-products, most of the GHG emissions are allocated to the F-T co-products because supercritical CO_2 has very low energy content. If GHG emissions are allocated on the basis of mass, most of the GHG emissions get allocated to supercritical CO_2, because the mass of supercritical CO_2 exceeds the mass of all the F-T co-products. This highlights the importance of all co-products having an underlying physical relationship between them; F-T liquid products and supercritical CO_2 do not. In this study, the allocation of GHG emissions was done using displacement for the supercritical CO_2 and a variety of methods for the F-T co-products as discussed in detail in **Appendix C**. The modified baseline system boundary for Scenarios 1-5 is presented in Figure 8.



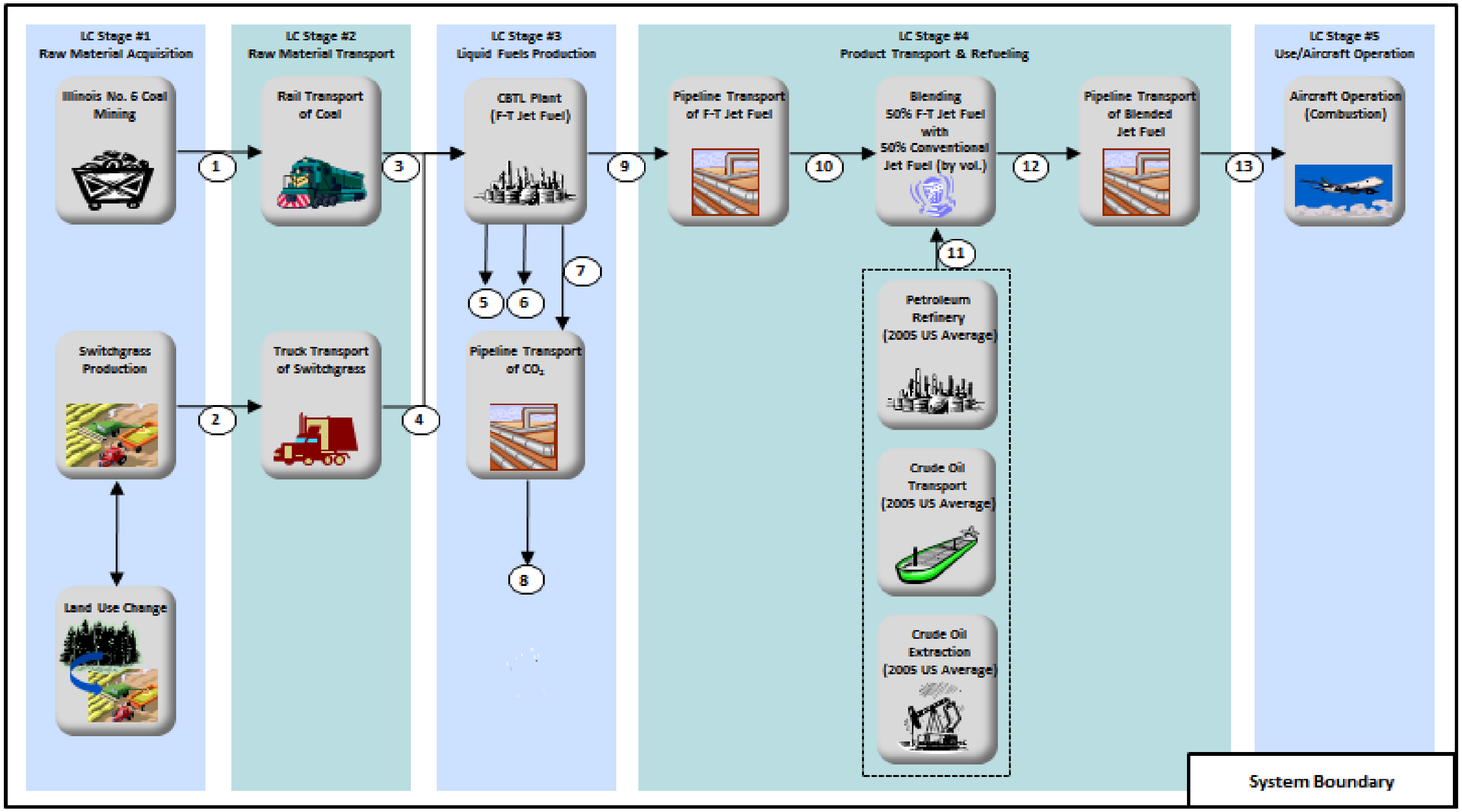
No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal	n/a	n/a	6	F-T Naphtha	n/a	n/a	11	F-T Jet Fuel	n/a	n/a
2	Switchgrass	n/a	n/a	7	Supercritical CO_2	n/a	n/a	12	F-T Jet Fuel	n/a	n/a
3	Illinois No. 6 Coal	n/a	n/a	8	Supercritical CO_2	n/a	n/a	13	Conv. Jet Fuel	n/a	n/a
4	Switchgrass	n/a	n/a	9	Crude Oil	n/a	n/a	14	Blended Jet Fuel	n/a	n/a
5	F-T Diesel	n/a	n/a	10	Natural Gas Liquids	n/a	n/a	15	Blended Jet Fuel	1	MJ, LHV

Figure 6. Baseline System Boundary for Scenarios 1-5 (CO_2-EOR Carbon Management Strategy)



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal	n/a	n/a	6	F-T Naphtha	n/a	n/a	11	Conv. Jet Fuel	n/a	n/a
2	Switchgrass	n/a	n/a	7	Supercritical CO_2	n/a	n/a	12	Blended Jet Fuel	n/a	n/a
3	Illinois No. 6 Coal	n/a	n/a	8	Supercritical CO_2	n/a	n/a	13	Blended Jet Fuel	1	MJ, LHV
4	Switchgrass	n/a	n/a	9	F-T Jet Fuel	n/a	n/a				
5	F-T Diesel	n/a	n/a	10	F-T Jet Fuel	n/a	n/a				

Figure 7. Baseline System Boundary for Scenarios 6-10 (Saline Aquifer Carbon Management Strategy)



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (AR)	n/a	g/MJ LHV	6	F-T Naphtha	n/a	g/MJ LHV	11	Conv. Jet Fuel	n/a	g/MJ LHV
2	Switchgrass	n/a	g/MJ LHV	7	Supercritical CO_2	n/a	g/MJ LHV	12	Blended Jet Fuel	n/a	g/MJ LHV
3	Illinois No. 6 Coal (AR)	n/a	g/MJ LHV	8	Supercritical CO_2	n/a	g/MJ LHV	13	Blended Jet Fuel	n/a	MJ, LHV
4	Switchgrass	n/a	g/MJ LHV	9	F-T Jet Fuel	n/a	g/MJ LHV	14			
5	F-T Diesel	n/a	g/MJ LHV	10	F-T Jet Fuel	n/a	g/MJ LHV	15			

Figure 8. Modified Baseline System Boundary for Scenarios 1-5 (CO_2 Co-Product)

3.2.5.2 Co-Product Allocation Options

ISO 14044 (2006b) states that inputs and outputs shall be allocated to the different co-products using process disaggregation, system expansion, or allocation. Figure 9 illustrates the decision process for developing an allocation approach for a product system contained in the Framework and Guidance Document (Allen, 2009).

The results of applying the decision process determined plausible allocation scenarios for the co-products in each of the 10 scenarios using the baseline system boundary. The results of the co-product allocation decision process steps from Figure 9 were as follows:

1. *Define the points where the multi-output processes (MOP) occur.*
    a. Baseline System Boundary, Scenarios 1-5, Life Cycle Stage #3
        i. CBTL Plant
            1. F-T Jet Fuel
            2. F-T Diesel Fuel
            3. F-T Naphtha
        ii. CO_2-EOR Operation
            1. Crude Oil
            2. Natural Gas Liquids
    b. Baseline System Boundary, Scenarios 6-10, Life Cycle Stage #3
        i. CBTL Plant
            1. F-T Jet Fuel
            2. F-T Diesel Fuel
            3. F-T Naphtha
            4. Supercritical CO_2
2. *Is the process as disaggregated as possible?* Yes.
3. *Describe co-products and develop baseline application that shows the results of alternative allocation approaches.* [See **Section 10** for results of alternative allocation approaches.]

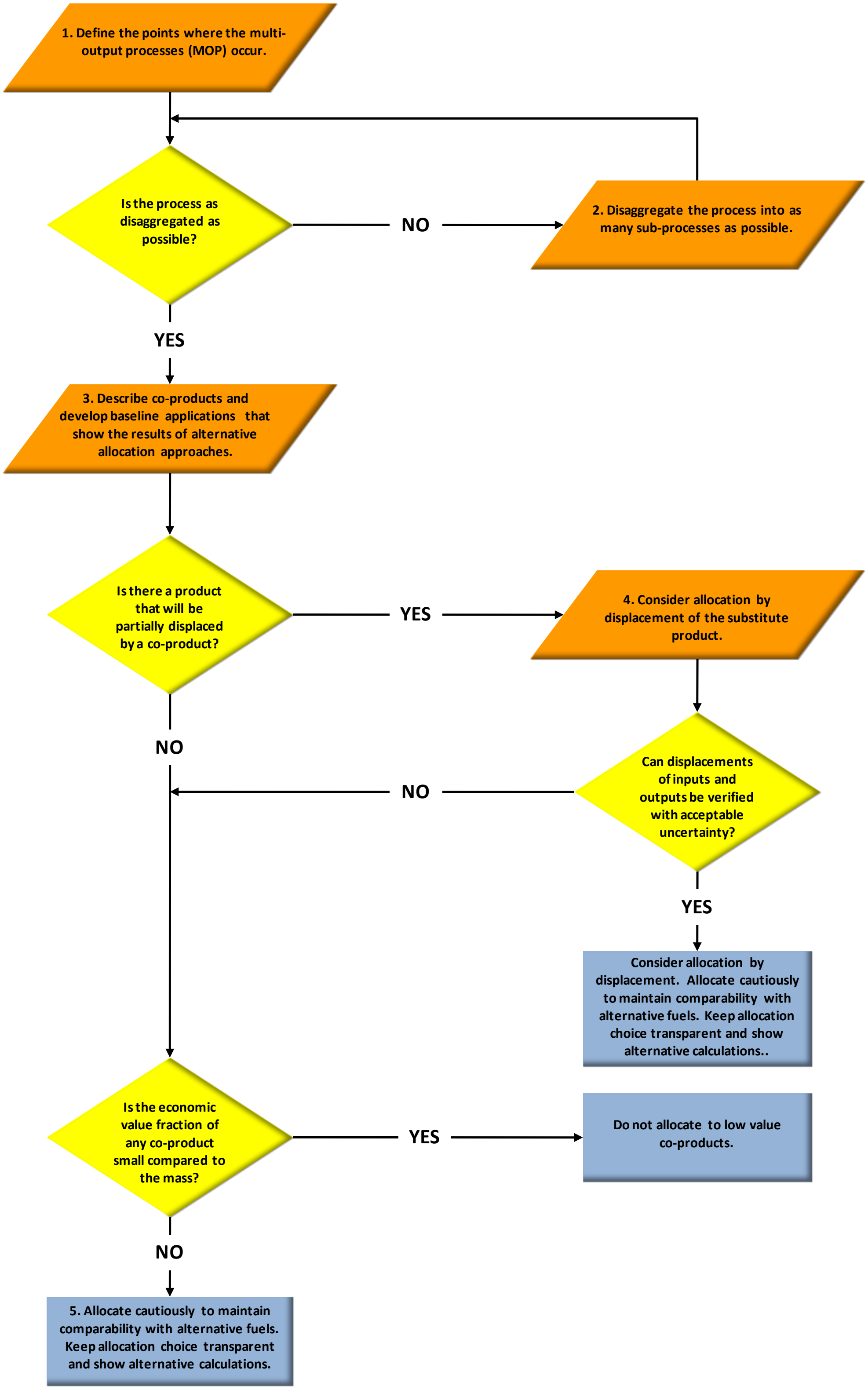


Figure 9. Illustration of the Process for Developing an Allocation Approach for a Product System (Allen, 2009)

a. Energy Allocation – All of the co-products identified in Step 1 above are related based on the physical property of energy density. All of the co-products are produced and sold for the primary purpose of performing work as produced or further refined to produce products that perform work (e.g., crude oil refined to conventional jet fuel). A limitation to performing the allocation by energy is the difference between "marketable" co-products and unrefined intermediate products, i.e., crude oil and natural gas liquids in the baseline system boundary. The unrefined co-product will require additional work to provide an equivalent marketable product that will result in additional GHG emissions. The choice of using the energy allocation procedure has the advantage of being the same as the metric for the functional unit for comparing the alternative fuel to the conventionally-produced fuel.

b. Mass and Volume Allocation – Both physical properties were evaluated as potential co-product allocation approaches. Volumetric allocation is a viable option as an alternative procedure for two reasons. First, all of the co-products are measured and sold on the basis of volume (i.e., CBTL plant produces 30,000 barrels per day (bbl/d) of F-T products; CO_2-EOR operation produces barrels of crude oil and natural gas liquids). Second, the conventional jet fuel production that each scenario is compared against applies a volumetric allocation procedure[2] when apportioning the environmental burdens between co-products produced at the petroleum refinery. Further, the Framework and Guidance Document states, "Clearly, when comparing products made with a similar process, the allocation needs to be done the same way for both processes in order to compare."

One drawback of volume allocation is that, unlike thermodynamic laws that govern the conservation of mass and energy, there is no physical basis for conservation of volume through a process. For instance, processing of feedstock into fuel at a CBTL facility, or at a petroleum refinery, or in support of another chemical transformation process, may result in an overall net increase or decrease in the volume of products, in comparison to the volume of inputs. Still, such changes in volume are expected to be minor in terms of F-T products from a CBTL facility. As a result, co-product allocation by volume has been identified as a potentially reasonable allocation option within this study. Mass allocation is the least preferred of the three physical allocation options due to the advantages of energy and, to a lesser extent, volumetric allocation, but is still a plausible

[2] The kerosene-based jet fuel baseline (NETL, 2008; Allen, 2009) uses a hybrid allocation procedure that disaggregates the petroleum refinery into key sub-processes and then determines the energy and hydrogen requirements for each sub-process. The volumetric flow through each sub-process, with respect to the slate of refined products, is used to allocate the energy, hydrogen, and operational burdens to the final products dependent on each sub-process. From a general perspective, this hybrid allocation approach is based on the volumetric throughput of each sub-process and therefore considered a volumetric allocation approach.

basis for allocation. In **Section 9**, allocation by all three methods (energy, volume, and mass) is presented and the results are shown to be similar (see Table 131**)**. Therefore, for the presentation of final results, energy was selected as the physical property used for allocation because all the co-products are produced and sold for the primary purpose of performing work.

c. Economic (Market Value) Allocation – Allocation by economic value has the advantage of attributing most of the environmental impact to the most valuable products. A disadvantage of using economic value to allocate inputs and outputs is that prices fluctuate over time. As prices change relative to each co-product, the GHG emissions will shift from lower value to higher value co-products even though nothing has physically changed in the system (see discussions in the Framework and Guidance Document). This allocation scheme would capture the relative utility of liquid fuel co-products, but considerable instability is introduced into the analysis by price volatility in the transportation fuels market and other energy markets. Therefore, an economic allocation approach was not considered for this study.

d. System Expansion / Displacement Allocation – In the displacement method, a co-product is assumed to displace a product with the same function and produced by a different process, typically at an unrelated facility. The Framework and Guidance Document, Chapter 5, provides guidance on using the displacement method and lists a series of advantages and disadvantages. The primary advantage is that it attempts to evaluate the actual change in environmental burdens from producing the alternative product and entering it into the marketplace. The challenge in this study is that while it is plausible that F-T diesel, F-T naphtha, crude oil, and natural gas liquids produced from the CBTL facility and CO_2-EOR operations may displace the need for existing sources of these fuel-related products, the complex interactions of market supply and demand may negate any real world displacement from occurring. A fuels market analysis that is capable of forecasting the change in supply and demand resulting from the operation of the CBTL facility and CO_2-EOR operations does not exist. In spite of these limitations, system expansion / displacement allocation was included in this study. As discussed in **Appendix C**, which presents the allocation of GHG emissions to co-products for the modified baseline system boundary, the differences in the physical characteristics of F-T fuels and supercritical CO_2 make allocation using energy, volume, or mass problematic. Thus, displacement was initially used to allocate GHG emissions to supercritical CO_2 before allocating the remaining GHG emissions among the F-T fuel co-products on an energy basis. This hybrid approach is preferred for this scenario;

however, it contradicts the allocation guidance provided in ISO 14044 (2006b) that states, “Allocation procedures shall be uniformly applied to similar inputs and outputs of the system under consideration.”

4. *Is there a product that will be partially displaced by a co-product?* Yes.
5. *Consider allocation by displacement of the substitute products.*
    a. Limitations for applying displacement are discussed above, under Item 3.
6. *Can displacement of inputs and outputs be verified with acceptable uncertainty?* Yes/No.
    a. This is a subjective question in which the answer can vary depending on the life cycle practitioner’s definition of acceptable. Because the purpose of this case study is to demonstrate the process provided in the Framework and Guidance Document, both the energy allocation and displacement methods are presented within this study.
7. *Is the economic value fraction of any co-product small compared to the mass?* The answer is no for the baseline system boundary and yes for the modified baseline system boundary because supercritical CO_2 has a much lower economic value than the F-T co-products.
8. *Last Step: Allocate cautiously to maintain comparability with alternative fuels. Keep allocation choice transparent and show alternative calculations.*

Based on the decision process discussed above for selecting alternative co-product allocation options, the following allocation procedures were evaluated within this study:

- Energy Allocation
- Volume Allocation
- Mass Allocation
- System Expansion/Displacement Allocation

Section 9 describes the calculation procedures used within the study for the allocation options, and **Section 10** provides a review of allocated results for each scenario. The energy and system expansion/ displacement options are the options selected for displaying and interpreting the final results of each of the 10 scenarios using the baseline system boundary.

3.2.6 Life Cycle Inventory Metrics

The scope of inventory metrics for this study is limited to GHG emissions, including carbon dioxide, methane, and nitrous oxide (Table 7). Many other GHGs have been identified as having high climate forcing potential. However, as relevant to the scope of this study, the working group has determined that these other GHGs are likely to have very low emission rates, such that they would provide an insignificant contribution to LC GHG emissions. For each LC stage considered in this study, GHG emissions from that stage will be attributed to at least one of four categories: operations, constructions, direct land use, and indirect land use. Throughout the

study, these four categories apply to intermediate flows, products, and co-products, as well as GHG emissions.

Table 7. Framework and Guidance Document LCI Metrics

Category	Primary Inventory Data	Reporting Metric per Functional Unit & Unit Process Reference Flow
Greenhouse Gases	Carbon Dioxide (CO_2) Methane (CH_4) Nitrous Oxide (N_2O) GHGs from Land Use (Direct) GHGs from Land Use (Indirect)	Mass of Pollutant Emitted to Atmosphere [Carbon Dioxide Equivalents (CO_2e)]

The inventory of GHGs emitted to the atmosphere is done on both a mass (kilograms [kg]) basis and in terms of the 100-year global warming potential (GWP) of each gas as determined by current and previous International Panel on Climate Change (IPCC, 2007, 2001, 1996) reports. Table 8 lists the primary GHGs and their corresponding GWP reported in mass of carbon dioxide equivalents (CO_2e). Other GHGs are considered insignificant in terms of relevance to this study, and therefore were not included.

Table 8. Primary Greenhouse Gas and Corresponding 100-Year Global Warming Potentials (IPCC, 2007, 2001, 1996)

Emissions to Air	Abbreviation	GWP_{2007} CO_2e	GWP_{2001} CO_2e	GWP_{1996} CO_2e
Carbon Dioxide	CO_2	1	1	1
Methane	CH_4	25	23	21
Nitrous Oxide	N_2O	298	296	310

3.2.6.1 Direct and Secondary Emissions

As discussed earlier, each stage (except land use) has an operation and construction unit process that lists material and energy inputs for the unit processes and the direct GHG emissions that result from the use of these inputs in the unit process. The material and energy inputs are typically refined products with GHG emissions occurring in the production or refining of these inputs. For example, in transporting coal by rail in Stage #2a, the locomotive burns diesel fuel and directly emits GHGs as a result of this combustion. The direct GHG emissions would be captured in the operation unit process for Stage #2a. However, before the diesel fuel can be burned, it must be produced. There are GHG emissions associated with extracting crude oil from the ground, transporting the crude oil to a refinery, refining the crude oil into diesel, and transporting the diesel to the locomotive. These upstream GHG emissions associated with diesel fuel are secondary emissions and are included in the secondary unit process for diesel fuel.

3.2.6.2 GHG Emissions Associated with Land Use Change

Analysis of land use effects associated with a process or product is considered a central component of an LCA investigation, under both ISO 14044 and draft American Society for Testing and Materials (ASTM) procedural standards. Additionally, the US Environmental Protection Agency (US EPA) finalized a series of new regulations for the National Renewable Fuel Standard Program for 2010 and beyond (US EPA, 2010a). The land use analysis presented in this study is consistent with the proposed methodology presented in the US EPA's Renewable

Fuel Standard 2 (RFS2), and quantifies both the area of land changed, as well as the GHG emissions associated with that change.

Land use effects can be roughly divided into direct and indirect. In the context of this study, direct land use emissions occur as a direct result of the LC processes needed to produce and deliver the jet fuel. Direct land use emissions are determined by tracking the change from an existing land use type (native vegetation, agricultural lands, and barren areas) to a new land use that supports production, and quantifying the GHG emissions associated with that change. Examples of facilities that result in land use change include coal mines and switchgrass farms.

Indirect land use effects are indirect changes in land use that occur as a result of the direct land use effects. For instance, if the primary effect is the conversion of food-producing agricultural land to switchgrass-producing agricultural land, indirect GHG emissions could result from the conversion of additional natural areas into agricultural land, to support production of the displaced agricultural land needed for food production. Both direct and indirect land use effects are relevant to the present study, which considers a wide-scale and potentially substantial shift from the use of conventional jet fuel feedstocks to alternative feedstocks, including switchgrass biomass. Additional discussion of methodologies for the quantification of direct and indirect land use are contained in **Section 4**.

3.2.7 Environmental LCI Modeling Tools

In support of this study, a new life cycle inventory (LCI) model (the F-T Jet Fuel Spreadsheet Model) was developed based on input from the Working Group. The F-T Jet Fuel Spreadsheet Model comprises a series of spreadsheet-based datasets and macros that were compiled and assembled by the Working Group. The F-T Jet Fuel Spreadsheet Model presents a life cycle inventory and GHG evaluation of the Fischer-Tropsch process for generating jet fuel from coal and biomass. The F-T Jet Fuel Spreadsheet Model is comprised of the following components:

- Each stage is divided into one or more unit process sheets with each sheet describing the input flows, output flows (products and co-products), and GHG emissions for its part of a stage. For each stage, one sheet is used to calculate operational flows and another sheet is used to calculate construction flows. In each sheet, the input flows, output flows, and GHG emissions are presented for the reference flow for that stage. For stages where land use change is considered important, one sheet is used to calculate GHG emissions associated with direct land use changes and a second sheet is used to calculate GHG emissions associated with indirect land use change.
- One sheet, sheet Sec.UP.All, provides the cradle to gate GHG emissions for all relevant secondary unit processes. For each secondary unit process, GHG emissions are presented relative to the reference flow for that unit process. For some secondary unit processes, the energy resources needed to produce the reference flow are also presented. For the secondary unit processes, the following sources were used to estimate the energy resource inputs and GHG emissions. Data from the NETL Petroleum Baseline LCA were used for crude oil extraction, transport, and refinery products. Natural gas secondary profiles were taken from the NETL Natural Gas Combined Cycle LCA, and were used as surrogate data for natural gas liquids. NETL electricity profiles were used for the Serc Reliability Corporation (SERC), the Midwest Reliability Organization (MRO) and the Electric Reliability Council of Texas (ERCOT) regions. Other NETL unit processes used include hydrogen, steel plate, 316 stainless steel, hot-dip galvanized steel, asphalt, and

mixed concrete. Another preferred source for secondary profiles was the Danish Environmental Design for Industrial Products (EDIP) database. Profiles from EDIP were used for cold-rolled steel, welded pipe, rebar, aluminum sheet, copper sheet, lead, zinc, nylon, polyurethane, and PVC pipe. Finally, data for the remaining materials was taken from Carnegie Melon's EIOLCA tool. These materials include lubricant; cast iron parts; rubber; Portland cement; hot-rolled steel; wood ties; granite gravel; lime; nitrogen, phosphorus, and potassium fertilizers; atrazine; amine; herbicide; seeds; plastic bale tarps and wraps; transport of cargo by ocean freighter, diesel rail, truck, and barge; pellet die; balers; bale movers; choppers; blowers; disks; drills; fertilizer and herb application; mowers; plows; rakes; and silos.

- For each stage, a sheet is provided which summarizes the input flows, output flows, and GHG emissions associated with all unit processes that comprise the stage. This summary sheet also includes secondary emissions from each input to the stage. The sheet includes the total input flows, output flows, and GHG emissions by operations, construction, direct land use (where applicable) and indirect land use (where applicable). The total input flows, output flows, and GHG emissions are presented for the entire stage. The input flows, output flows, and GHG emissions are presented relative to the stage reference flow and the system functional unit.
- For the system as a whole, a sheet is provided that summarizes the input flows, output flows, and GHG emissions for all stages. The sheet includes the total input flows, output flows, and GHG emissions by operations, construction, direct land use, and indirect land use. The total input flows, output flows, and GHG emissions are also presented for the entire system. The input flows, output flows, and GHG emissions are presented relative to the system functional unit. This sheet presents unallocated input flows, output flows, and GH emissions.
- For GHG emissions, a sheet is provided that allocates the GHG emissions for the entire system between the various co-products using the allocation methods described previously.
- The F-T Jet Fuel Spreadsheet Model includes a number of macros that facilitate the evaluation. In the unit process sheets, equations are used that describe the relationship between inputs, outputs, and emissions. Many of these equations have parameters that are uncertain. One macro allows the uncertainty in the parameters to be specified as a probability distribution. For each stage and for the system as a whole, the uncertainty in GHG emissions resulting from uncertainty in multiple parameters is calculated by the macro. Another macro allows the influence of uncertain parameters on GHG emissions to be evaluated in a systematic sensitivity analysis.
- The F-T Jet Fuel Spreadsheet Model is available for public download, and can be found at www.netl.doe/gov/energy-analyses.
- The F-T Jet Fuel Spreadsheet Model calculates almost all the results presented in this report. The F-T Jet Fuel Spreadsheet Model also has a description of many of the equations and parameters used to perform the various calculations. Therefore, throughout this report, reference is made to specific sheets in the F-T Jet Fuel Spreadsheet Model where the interested reader can find additional details.

3.2.8 Summary of Modeling Choices

Table 9 summarizes the modeling choices for the primary flow pathway of this LCA. These choices were defined by consensus of the working group. Significance of these choices is evaluated as part of the larger uncertainty and sensitivity analysis described in **Section 3.3**. Results of the sensitivity analysis are available in **Section 10**.

As with any model used to approximate a process, many additional assumptions to those outlined in Table 9 are made in the calculation of subprocess flow values and assembly of the model. Those assumptions are outlined within the sections describing each lifecycle stage.

Table 9. Study Modeling Choices by LC Stage

Primary Subject	Modeling Choice
Study Boundary Choices	
Temporal Boundary	30 years
Region	US Midwest and South
LC Stage #1a: Coal Feedstock	
Coal Feedstock	Illinois No. 6 Bituminous Coal
Extraction Location	Southern Illinois
Representative Mine	Galatia Mine, Galatia, Illinois
Operating Lifetime	30 years
Moisture Content of Delivered Coal	0.111 kg/kg
Carbon Content of Delivered Coal	0.6375 kg/kg
LC Stage #1b: Switchgrass Biomass	
Moisture Content of Delivered Biomass	0.15 kg/kg
Carbon Content of Delivered Biomass	0.4226 kg/kg
Cultivation Period	1 year
Land Use Type	Converted Cropland and Pastureland
Location	East-Central Iowa, Missouri
Baling Scenarios	Rectangular Bales, Covered; Round Bales, Covered: Round Bales, Uncovered
LC Stage #1c: Land Use	
Land Use Metrics Considered	GHG Emissions
Land Use Scope	Direct and Indirect Impacts
LC Stage #2a: Coal Transport (Mine to CBTL Facility)	
Coal Transport One-way Distance	200 miles by rail
Coal Mine Rail Spur Constructed Length	25 miles
LC Stage #2b: Switchgrass Transport	
Switchgrass Transport One-way Distance	25 miles by truck
LC Stage #3a: Energy Conversion Facility	
Location	Northwest Missouri
Plant Capacity	30,000 bbl/d
Fraction of Jet Fuel Product to Total Facility Product	Varies based on CBTL operating scenario
Density of F-T Jet Fuel	0.751-0.754 kg/L
Carbon Content of F-T Jet Fuel	0.848-0.850 kg/kg
Density of F-T Diesel	0.784 kg/L

Table 9. Study Modeling Choices by LC Stage *(Cont'd)*

Primary Subject	Modeling Choice
LC Stage #3a: Energy Conversion Facility *(Cont'd)*	
Carbon Content of F-T Diesel	0.851 kg/kg
Density of F-T Naphtha	0.676-0.681 kg/L
Carbon Content of F-T Naphtha	0.839-0.840 kg/kg
F-T Catalyst Employed	Iron or Cobalt
Type of Reactor	Bubble Slurry
Fraction of Unreacted Syngas Recycled to the F-T Reactor	Iron Catalyst: 0% Cobalt Catalyst: 50%
Autothermal Reforming	Iron Catalyst: No Cobalt Catalyst: Yes
LC Stage #3b: CO_2 Pipeline Transport to Enhanced Oil Recovery	
CO_2 Pipeline Point to Point Distance	775 miles
Fugitive CO_2 Loss	Approximately 0.1% of CO_2 input
LC Stage #3c: CO_2 Enhanced Oil Recovery	
Primary Subject	Modeling Choice
Enhanced Oil Recovery Location	Permian Basin, Texas
CO_2 Injection Procedure	Water-Alternating Gas (WAG)
Fugitive CO_2 Loss	Approximately 0.5% of CO_2 input
LC Stage #3d: Saline Aquifer Carbon Dioxide Sequestration	
CO_2 Pipeline Distance	100 miles
Fugitive CO_2 Loss	0.5% of CO_2 input
LC Stage #4: Product Transport	
Petroleum Refinery Location	Wood River, Illinois
Point to Point Distance from CBTL to Petroleum Refinery	225 miles
Method for Transporting F-T Jet Fuel to Refinery	pipeline
Petroleum Jet Fuel to F-T Jet Fuel Ratio of Mixed Delivered Fuel	50% by volume
Airport Location (Option 1)	Chicago O'Hare
Point to Point Distance from Petroleum Refinery to Airport (Option 1)	245 miles
Method for Transporting Blended Jet Fuel to O'Hare Airport (Option 1)	pipeline
Point to Point Distance from Petroleum Refinery to Bulk Storage Facility (Option 2)	100 miles
Method for Transporting Blended Jet Fuel to Bulk Storage Facility (Option 2)	pipeline
Portion of Jet Fuel to Local Airports (Option 2)	40% by mass
One-way Distance from Bulk Storage Facility to Regional Airports (Option 2)	50 miles
Method for Transporting Blended Jet Fuel to Regional Airports (Option 2)	tanker trucks
Point to Point Distance from Bulk Storage Facility to Chicago O'Hare (Option 2)	160 miles
Method for Transporting Blended Jet Fuel to O'Hare Airport (Option 2)	pipeline

3.3 Data Quality Approach

Data quality is evaluated for both the collected sources and for assimilated data sets according to the recommended procedure in the Framework and Guidance Document. An evaluation of quality and the effect of uncertainty on final results are performed for:

- Uncertainty in life cycle inventory data
- Uncertainty in modeling choices
- Uncertainty in scenario choices

3.3.1 Data Uncertainty Evaluation Method

To determine whether available literature contains the appropriate level of quality to be considered for inclusion as a data source, an evaluation of each data source was performed. Once a data source was selected for the LCI, a representation of each source was included in a data quality matrix for each unit process.

The matrix is intended to provide a qualitative determination of the quality of data used for each unit process, giving insight into areas where sensitivity analysis or additional data collection might be required. A Data Quality Indicator (DQI) is a five digit number, each number of which corresponds to the five quality indicators listed in Table 10: source reliability, completeness, temporal correlation, geographical correlation, technological correlation. Additional detail regarding the five quality indicators, including procedural determinations, can be found in the Framework and Guidance Document.

Table 10. Data Quality Indicators for Use in the Data Quality Matrix

Indicator	Score				
	1	2	3	4	5
Source Reliability	Data verified based on measurements	Data verified based on some assumptions and/or standard science and engineering calculations	Data verified with many assumptions, or non-verified but from quality source	Qualified estimate	Non-qualified estimate
	Source quality guidelines met		Source quality guidelines not met		
	Data cross checks, greater than or equal to 3 quality sources	2 or less data sources available for cross check, or data sources available that do not meet quality standards		No data available for cross check	
Completeness	Representative data from a sufficient sample of sites over an adequate period of time	Smaller number of site but an adequate period of time	Sufficient number of sites but a less adequate period of time	Smaller number of sites and shorter periods or incomplete data from an adequate number of sites or periods	Representativeness unknown or incomplete data sets

Table 10. Data Quality Indicators for Use in the Data Quality Matrix *(Cont'd)*

Indicator	Score				
	1	2	3	4	5
Temporal Correlation	Less than three years of difference to year of study	Less than 6 years of difference	Less than 10 years of difference	Less than 15 years of difference	Age of data unknown or more than 15 years of difference
Geographical Correlation	Data from area under study	Average data from larger area	Data from area with similar production conditions	Data from area with slightly similar production conditions	Data from unknown area or area with very different production conditions
Further Technological Correlation	Data from technology, process or materials being studied	Data from a different technology using the same process and/or materials		Data on related process or material using the same technology	Data or related process or material using a different technology

All unit processes that scored a three, four, or five in any of the five data quality categories were further evaluated to assess the uncertainty introduced by data that failed to meet the goal and scope of the study. Expressed in terms of a probability distribution, the inputs for high quality unit processes (DQI 1 or 2) were varied to a maximum and minimum value or 95 percent confidence interval. If no information was available to determine, or estimate, the uncertainty range, a default range of +/- 10 percent was applied to unit processes with a DQI of 1 or 2. The inputs of low quality unit processes (DQI 3-5) were also varied to maximum and minimum values or 95 percent confidence interval of the uncertainty range; however, a default range of +/- 10 percent was not applied, and additional research was performed to determine a representative uncertainty range. Results of the final significance analysis are provided in **Section 10**.

If changes to the final result from a single unit process were greater than 0.1 g CO_2e/MJ jet fuel (significance threshold), the process was flagged for data quality refinement. In cases where uncertainty due to poor data quality could not be reduced sufficiently to reduce the model response below the significance threshold, uncertainty analysis as relevant to the study outcomes are included in **Section 10**.

3.3.2 Uncertainty Evaluation Method for Modeling Choices

Model uncertainty is classified as any modeling choice that could not be adequately supported by data. Modeling choices listed in Table 9 that were not supported by data, but required professional judgment, were evaluated for the effect of uncertainty significance to the total life cycle GWP results. Uncertainty inherent in these choices was represented as either a probability distribution or a set of parametric choices. For example, the selection of an allocation method is a distinct model parametric choice. Results of sensitivity analysis are provided in **Section 10** to report choices with a significant effect to the study results. Any modeling choice causing uncertainty greater than 0.1 g CO_2e/MJ jet fuel is regarded as a significant data limitation.

3.3.3 Scenario Uncertainty Evaluation Method

Scenario uncertainty is introduced into the study when primary operations cannot be defined for the system boundary, because more than one option exists for how an operation will be conducted. Also, scenario uncertainty is informed by the entity conducting the LCA. In this study, it is assumed that a GHG LCA for alternative jet fuels would be conducted by entities interested in producing jet fuel manufactured in part at CBTL plants. These entities can control process conditions within the CBTL plant but have less control over the practices of their supply chain and over the disposition of the products they produce.

In this study, two forms of scenario uncertainty were included to demonstrate the principles of scenario uncertainty as described in the Framework and Guidance Document. The first is in the LC Stage #1 for switchgrass production. It was assumed that the method in which the switchgrass is collected and stored is outside the control of the CBTL plant. Switchgrass may be collected in the form of rectangular bales or round bales. Also, the storage method of the switchgrass at the farm can vary from being stored in a shed, stacked and covered with a tarp, and wrapped in twine and elevated. It is assumed that the switchgrass collection and storage method is not specified by the CBTL plant as part of its biomass feedstock contract. Therefore, each of these options is plausible and results in scenario uncertainty within the study. Similarly, the CBTL plant recognizes that the blended jet fuel product may be distributed in multiple ways to potentially more than one airport. Recognizing and including these forms of uncertainty in the study is intended to address areas within the life cycle that are not well defined and expand the envelope of production or delivery options for the alternative jet fuel under consideration.

For the purposes of this study, the sources of scenario uncertainty considered are described in Table 11. Scenario options for switchgrass production are discussed in **Section 4**; options for CBTL processing are described in **Section 6**; and the blended jet fuel delivery options are discussed in **Section 7**. The 10 alternative pathways evaluated in this study (referred to as Scenarios 1 thru 10 in Table 4) are not forms of "scenario uncertainty" because they are considered 10 independent life cycle assessments conducted and summarized within this report.

Table 11. Sources of Scenario Uncertainty (Model Options)

Life Cycle Stage	Scenario Options
LC Stage #1b: Switchgrass Production	Rectangular Bales, Covered (Option 1, Base Case)
	Round Bales, Covered (Option 2)
	Round Bales, Uncovered (Option 3)
LC Stage #4c: Blended Jet Fuel Transport	Blended Jet Fuel Transport to Chicago O'Hare Airport (Option 1, Base Case)
	Blended Jet Fuel Transport to Chicago O'Hare Airport and Regional Airports (Option 2)

Secondary scenario uncertainty, introduced from different switchgrass management options and the blended jet fuel transport options, was determined at the LC stage level to have negligible significance on the interpretation of the final results. Table 12 confirms that at the system level, the difference in total GHG emissions for these options is negligible. The difference in total GHG emissions for each option compared to the baseline option is within the range of 0 percent to 0.07 percent, which is a considered negligible. As a result, secondary scenario uncertainty introduced by switchgrass production options and blended jet fuel transport options is considered negligible, and is not included in the discussion of the scenario results in **Section 10**. The base

case for switchgrass production (rectangular bales, shed) and blended jet fuel transport (option 1) was selected to report final scenario results.

Table 12. Effect of Switchgrass Production Options on Deterministic Study Results

Scenario	System Boundary	% Change from Switchgrass Management Option 1: Rectangular Bales, Shed (Base Case)		% Change from Blended Jet Fuel Transport Option1: 100% Pipeline (Base Case)
		Option 2: Round Bales, Tarp Covered, Stacked	Option 3: Round Bales, Twine Wrap, Elevated	Option 2: 60% Pipeline, 40% Truck
1	Baseline	0.02%	0.02%	-0.04%
2	Baseline	0.00%	-0.01%	-0.06%
3	Baseline	0.00%	-0.02%	-0.06%
4	Baseline	0.00%	-0.01%	-0.06%
5	Baseline	0.00%	-0.01%	-0.06%
6	Baseline	0.00%	0.00%	-0.06%
7	Baseline	0.00%	-0.03%	-0.06%
8	Baseline	-0.01%	-0.07%	-0.07%
9	Baseline	0.00%	-0.02%	-0.06%
10	Baseline	0.00%	-0.02%	-0.06%

Note: Change in deterministic results is based on energy allocation using IPCC 2007 100-yr GWPs.

3.4 Life Cycle Stage Results Interpretation

A life cycle assessment involves the collection of a great deal of primary information and a significant amount of processing of the assembled data. The volume of information collected can make interpretation of the results difficult. To facilitate the interpretation, the life cycle GHG emissions were analyzed three ways:

- Deterministic Analysis
- Probability Uncertainty Analysis
- Sensitivity Analysis

In a deterministic analysis, a single value is selected for each uncertain variable and used in the F-T Jet Fuel Spreadsheet Model to calculate GHG emissions. In this evaluation, each uncertain variable is set to its "best estimate" when performing the deterministic analysis. The best estimate is typically a value selected based on best professional judgment. In many cases, the best estimate is the average value of the distribution assigned to an uncertain parameter. The deterministic analysis results in a single value for each input flow, output flow, and GHG emission, as well as a single value for the CO_2e emission for the overall system.

In a probabilistic analysis, each uncertain variable is treated as a random variable with a probability distribution. In a probabilistic simulation, the model calculating life cycle GHG emissions is calculated over and over again, with each calculation of the model referred to as an iteration. In each iteration, a value is randomly selected for each random variable from its distribution and the model is executed, resulting in a value for each GHG emission. The results for each GHG for a single iteration are stored and the process is repeated many times (2000 iterations were performed for each evaluation) resulting in many estimates of GHG emissions. After all the iterations are completed, the stored results are used to construct a distribution for each GHG emission, and to calculate statistics for each GHG emission. In this evaluation,

probabilistic simulations were performed for total life cycle GHG emissions using the IPCC 2007 global warming potentials. In the F-T Jet Fuel Spreadsheet Model, the sheet "Prob & SA Control" provides more detail on the process used to perform the probabilistic uncertainty analysis.

Table 13. Uncertainty Ranges for Secondary Unit Processes (Energy Processes Only)

Process Name	Minimum (% above best value)	Maximum (% below best value)	Distribution
Petroleum Diesel	-5%	+5%	Triangular
Petroleum Gasoline	-5%	+5%	Triangular
Petroleum Jet Fuel	-5%	+5%	Triangular
Natural Gas	-5%	+10%	Triangular
Natural Gas Liquids	-5%	+10%	Triangular
SERC Electricity	-10%	+10%	Triangular
MRO Electricity	-10%	+10%	Triangular
ERCOT Electricity	-10%	+10%	Triangular

The GHG emissions for the secondary unit processes are provided in sheet Sec.UP.All. After constructing and analyzing the results of the F-T Jet Fuel Spreadsheet Model, it became apparent that the only secondary unit processes that contribute significant GHG emissions to the total are energy unit processes (i.e., gasoline, diesel, conventional jet fuel, natural gas, natural gas liquids and electricity). The other secondary unit processes are material inputs and their contributions to GHG emissions occur in the construction unit processes. The GHG emissions for construction are less than 1 percent of the total life cycle GHG emissions. Therefore, although there is uncertainty in the GHG emissions associated with these material inputs, this uncertainty was not quantified (except in a few instances where the data was readily available). However, the uncertainty in the GHG emissions from the energy inputs was quantified. The distributions specified for each energy unit process can be found in sheet Sec.UP.All and Table 13.

In a sensitivity analysis, each uncertain variable is independently adjusted to its minimum and maximum values to determine how that variable affects a reported GHG emission. The following procedure was used to perform the sensitivity analysis on life cycle GHG emissions.

- First, all the key variables for each LC stage were set to their best estimate, and the total CO_2e emission was calculated using IPCC 2007 global warming potentials. This value becomes the baseline value for CO_2e emissions.
- Second, one of the key variables is changed to the maximum value and the total CO_2e emission is calculated and stored.
- Third, the same key variable is changed to the minimum value and the total CO_2e emission is calculated and stored.
- Fourth, at the conclusion of step three, the value of the key value is returned to its average value. The absolute value of the two CO_2e emission values (one calculated when the key variable is its maximum and the other calculated when the key variable is its minimum) is a measure of the degree of influence that the key variable has on the CO_2e

emission. The absolute value of the two CO_2e emission values is referred to as the Absolute Difference.

- Steps 2 through 4 are repeated for all key variables to generate an absolute difference for each key variable.
- After steps 2 through 4 have been performed on all key variables, the key variables are sorted from largest to smallest based on their absolute difference.
- The results for all key variables are presented graphically in a Tornado chart, which plots the Absolute Difference for each key variable from largest to smallest about the baseline value.

In the F-T Jet Fuel Spreadsheet Model, the sheet “Prob & SA Control” provides more detail on the process used to perform the sensitivity analysis.

4.0 LC STAGE #1: RAW MATERIAL ACQUISITION

This stage includes three primary activities: 1) coal mining, 2) switchgrass production, and 3) direct and indirect land use changes from switchgrass production. The development of life cycle inventory data was divided into three sub-groups within the IAWG-AF using the following boundary conditions.

LC Stage #1a: Illinois No. 6 Coal Extraction. The LC Stage #1a boundary starts with the acquisition of Illinois No. 6 coal from an underground mine via a longwall mining process. The coal is transported to the surface, cleaned (i.e., coal is separated from inorganic rock), and stockpiled. The boundary ends with the loading of Illinois No. 6 coal onto a train for transport under LC Stage #2a.

LC Stage #1b: Switchgrass Biomass Production. The LC Stage #1b boundary starts with the preparation of land in support of the agricultural production of switchgrass. The switchgrass is seeded, cultivated, harvested, and processed into either rectangular or round bales and stored at the farm until transport. The boundary ends with the loading of the bales of switchgrass onto trucks for transport under LC Stage #2b.

LC Stage #1c: Direct and Indirect Land Use. The LC Stage #1c boundary includes GHG emissions associated with land use change as a result of switchgrass production. The land use analysis includes direct land use effects and indirect land use effects. Direct land use effects are changes in GHG emissions associated with converting a specific parcel of land from one use (such as growing row crops or pasture crops) to another use (switchgrass production). Indirect land use effects arise when the new land use (switchgrass production) displaces land used for necessary agricultural activities (such as growing food crops). To make up for the displaced crops, other land not currently used for agricultural production must be converted to agricultural use to grow the displaced crops. The indirect land use analysis evaluates how changing land area from non-agricultural to agricultural use changes GHG emissions. While land use changes can occur at any stage, growing switchgrass results in the largest changes in land use, by far, of all stages. The land use changes associated with each stage are discussed in greater detail in this section, demonstrating that switchgrass production results in the largest land use change. The boundary for LC Stage #1c is consistent with LC Stage #1b.

4.1 Illinois No. 6 Coal Mining (LC Stage #1a)

Life cycle Stage #1a models the extraction of Illinois No. 6 bituminous coal from an underground coal mine located in southern Illinois. The system boundary for LC Stage #1a starts with undisturbed coal in the earth and ends with the loading of coal into railcars. It is assumed that the coal is obtained from underground mines, since roughly 80 percent of the coal mined in Illinois comes from underground mines (Illinois DNR, 2008). As discussed in **Section 5**, between 9,000 and 11,600 tonnes of coal will be needed each day by the CBTL facility, or between 3.3 million and 4.2 million tonnes each year (3.62 million to 4.67 million short tons of coal per year).

It was assumed that all coal would be obtained from several underground coal mines in the Southern Illinois region. The F-T facility will obtain mid- to long-term contracts with one or more mines in the area to balance supply stability, price, and other external factors. Underground mining operations were modeled based on information for the Galatia mine in Saline County, Illinois. The Galatia Mine produces about 6 million tonnes of coal each year, so

the Galatia mine is an appropriately sized coal mine for this evaluation. There is information on this mine in the public domain and additional information was obtained by NETL personnel through interviews with mine employees. When possible, information on the Galatia mine was used as the basis for this evaluation. The F-T Jet Fuel Spreadsheet Model accounts for manufacture of equipment used in coal mining, construction of the coal mine facilities (e.g., buildings and roads), installation of equipment, operation of the coal mine, and closure of the mine at the end of the study period.

The modeling approach, data quality assessment, and life cycle stage results relative to the reference flow for this stage, which is 1 kg of coal ready for transport, are presented below.

4.1.1 Modeling Approach and Data Sources

The properties of Illinois No. 6 bituminous coal are shown in Table 14. Bituminous coal is the most abundant of the four coal ranks (bituminous, sub-bituminous, lignite, and anthracite) and possesses properties that make it conducive to use in an F-T process (EERE, 2002). As discussed previously, the Galatia mine was chosen to represent the extraction of Illinois No. 6 coal. Table 15 lists key assumptions made in modeling Illinois No. 6 coal extraction.

Table 14. Properties of Illinois No. 6 Coal (NETL, 2007a)

Rank	Bituminous	
Seam	Illinois No. 6 (Herrin)	
Source	Old Ben Mine	
Proximate Analysis (weight %)		
	As Received	Dry
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Sulfur	2.51	2.82
Total	102.512.51	102.82
HHV, kJ/kg	27,113	30,506
HHV, Btu/lb	11,666	13,126
LHV, kJ/kg	26,151	29,544
LHV, Btu/lb	11,252	12,712
Ultimate Analysis (weight %)		
	As Received	Dry
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen	6.88	7.75
Total	100.00	100.00

Table 15. Key Assumptions for Illinois No. 6 Coal Acquisition

Primary Subject	Assumption	Basis	Source
Coal type	Illinois No. 6	Proximity to US switchgrass resource	NETL 2010a
Extraction location	Southern Illinois	Extraction location of Illinois No. 6 coal	NETL 2010a
Representative mine	Galatia Mine	Geographic, temporal, and technical representativeness of Illinois No. 6 coal extraction	Study Value
Plant Lifetime	30 years	Assumption	Study Value
Extraction method	Underground longwall mining	Extraction method of Galatia mine	US EPA, 2008
2008 Annual Coal Mine Production	6.38 million short tons/year	Average mine coal production between 2002-2006	US EPA, 2008
Coal feedstock particle size	17 percent less than 200 mesh	NETL reported feedstock preparation requirements	NETL, 2009a
Coal bed methane generated	150 ft^3 CH_4/ton coal	Low to moderate gassy mines in Southern Illinois	Study Value derived from Tarka, 2010b
Mine decommissioning energy use and emissions	10% of installation energy use and emissions	Assumption	NETL Engineering Judgment

4.1.1.1 Overview of Coal Mining Process

Information was obtained for the Galatia Mine from literature review and phone interviews with mine staff (DNR, 2005; US EPA, 2008). An underground mine operating in Galatia, Illinois, Galatia Mine's current operations primarily utilize the longwall mining technique (US EPA, 2008).

Longwall mining and room-and-pillar mining are the two most commonly employed methods of underground coal mining in the United States. These underground mining techniques were used to produce approximately 86 percent of the coal mined in the Herrin (No. 6) coal bed in 2008 (EIA, 2008). In contrast to the room-and-pillar mining method, in which "rooms" are excavated from the mine seam and "pillars" are left in place between rooms to support the mine roof, longwall mining results in the extraction of long rectangular blocks, or "panels," of coal, and the collapse of the roof following coal extraction (EIA, 1995). However, before longwall mining can begin, the mine workings must be prepared by "blocking out" the panel—excavating passageways and staging areas around the perimeter of the panel to be mined. Blocking out is a room-and-pillar type operation that can be accomplished using a coal–cutting machine referred to as a continuous miner.

During the coal extraction phase of the operations, the longwall unit is set up along the face of the panel, which can be upwards of 1,000 feet wide, from inches to seven feet high, and 7,000 feet long (EERE, 2002; EIA, 1995). Extraction begins under movable hydraulic roof supports called shields. A coal cutting machine, or shearer, cuts back and forth along the entire panel to remove coal from the mine face. The cut coal falls onto an armored chain conveyor that runs the entire length of the panel. The chain conveyor dumps the coal onto a belt conveyor, which carries the coal out of the mine (EERE, 2002; EIA, 1995; MSEC, 2007). As the longwall miner cuts a section of the panel away, the shields advance forward with the unit. The roof that the shields had been supporting is allowed to collapse.

The large-scale, continuous, and semi-automated nature of longwall mining makes the average operation more productive than traditional room-and-pillar operations. Other advantages include lower average worker requirements and improved safety resulting from more predictable mine roof collapse. Disadvantages of longwall mining include higher capital costs to purchase the mining, conveyance, and roof support machinery, low mine productivity during the panel development period of operations, and the release of substantial amounts of CH_4 compared to room-and-pillar mining (EIA, 1995). Because of the rapid rate of coal extraction, substantial dust is generated by the coal cutting machine. Dust is increasingly suppressed by spraying water at the cutting face.

Following mining, coal from both the room and pillar mining and longwall mining processes is conveyed from the mine to the surface using an electrically-driven slope conveyance system. At the surface, coal is transferred from the slope conveyor to a stacker/reclaimer that stockpiles the coal adjacent to the coal cleaning facility. The stockpiled coal is processed through a coal crusher facility (to be sized) and the coal cleaning facility. The cleaned and dewatered coal is transferred to a loading silo, where it is stored until being loaded into railcars for transport. Reject material is partially dewatered and transferred to an onsite impoundment for storage.

4.1.1.2 Life Cycle Inventory Model

Figure 10 gives the individual processes modeled in the Illinois No. 6 coal acquisition stage. Construction processes are modeled using vendor data and specifications for representative pieces of equipment. The commissioning/decommissioning and operation processes are modeled using data from the Galatia Mine. Where data were not available from the Galatia Mine, information from other Illinois No. 6 production mines was used, if possible. In some cases, due to lack of available data, information from mines located in other parts of the US was used.

Figure 10 shows that 17 individual construction unit processes are represented in the coal mine construction process, each representing a single piece of equipment or component of the mine site. For this stage, construction includes the material needed to manufacture the equipment used in an underground coal mine. These pieces of equipment and components are grouped into three construction assembly blocks. The first construction assembly block, construction of the underground coal mine system, assembles the materials needed to install longwall mining systems, continuous miners, and a central conveyor system. The longwall mining system consists of a number of distinct pieces of equipment. The continuous miners are used in conjunction with shuttle cars to extract coal. Both the longwall mining systems and continuous miners use the conveyor system to move the extracted run-of-mine coal to the surface.

The second construction assembly block assembles the materials needed to construct the coal preparation facility. This facility consists of a number of distinct components that remove the run-of-mine coal from the conveyor system, temporarily store the coal, crush the coal, separate the coal from inorganic materials, and load the cleaned coal into coal railcars for transport to the CBTL facility. A wastewater treatment facility is also included at the coal mine site, and is used to reduce stormwater sediment loads and treat stormwater-derived leachate from stockpiles on site, prior to discharge into a nearby river. A third construction assembly block is used for determining the concrete and asphalt needed to construct site buildings and pave onsite roads and parking lots.

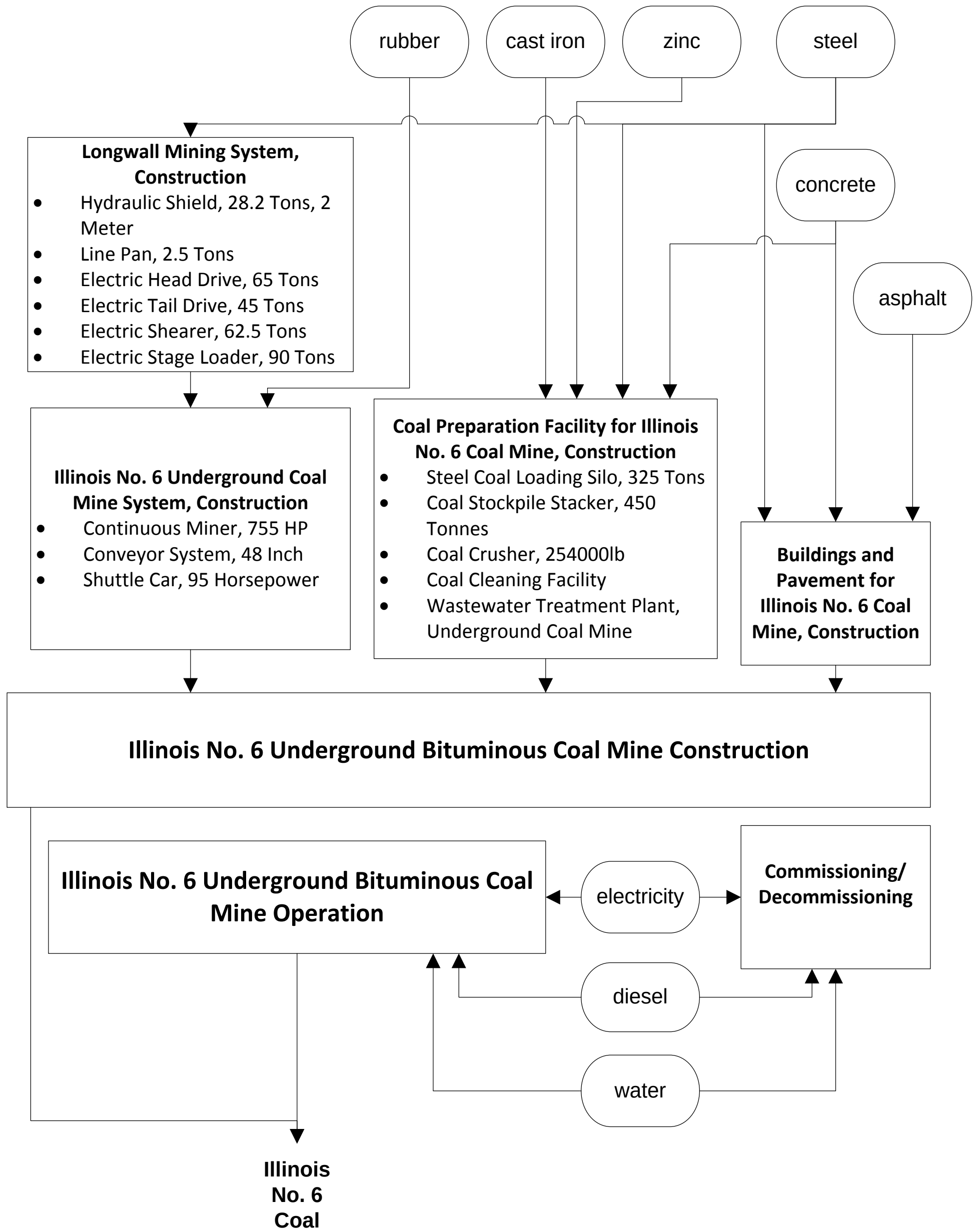


Figure 10. Illinois No. 6 Coal Acquisition Processes

The process of building the mine is termed installation or commissioning in this LC stage. The process of closing the mine at the end of its productive life and returning the land to its original use is termed de-installation or decommissioning. Commissioning and decommissioning of the coal mine accounts for the energy needed (principally diesel fuel and gasoline) for the commissioning and decommissioning activities, including installation and removal of major facilities on site. These data were not available for the Galatia Mine, so data from environmental impact statements (EIS) for similar coal mines (Hillsboro, 2007; Sugar Camp, 2007), as well as other literature sources, were used. The inputs and outputs from commissioning and decommissioning are included in the construction category when reporting results. Note that

materials requirements for various elements of the mine are accounted for in the construction unit processes, described previously.

Operation of the mine is modeled in a single unit process that accounts for the energy used to operate the underground coal mine for the study period. The energy sources are electricity and diesel fuel. The Illinois No. 6 coal mine operations unit process also quantifies coal bed methane emissions.

LC Stage #1a is implemented in the F-T Jet Fuel Spreadsheet Model through a number of sheets. For operations, all the input flows, output flows and GHG emissions are determined in sheet S1a.UP.O.CoalMOp. The input flows are:

- Diesel fuel
- Electricity

The output flows are:

- Coal ready for transport (reference flow)
- Mining-derived coal particulates (fugitive dust emissions)

The GHG emissions are CO_2 from non-biogenic sources, CO_2 from biogenic sources (zero for this stage), CH_4 and N_2O.

The sheet includes additional flows to facilitate mass balance calculations. For coal, additional flows include "run-of-mine coal" (total coal extracted from earth) and "mining residuals." The run-of-mine coal is divided between the coal ready for transport, mining residuals, and mining-derived coal particulates. Because run-of-mine coal and mining residuals are within the stage boundary, they are technically neither input nor output flows. For GHGs, additional flows include "coal bed methane captured and combusted," "coal bed methane released," "CO_2 to air from combustion," "CH_4 to air from combustion," and "N_2O to air from combustion." The flows "coal bed methane captured and combusted" (after it has been converted to CO_2) and "CO_2 to air from combustion" are summed to give the total CO_2 emitted to the atmosphere. The flows "coal bed methane released" and "CH_4 to air from combustion" are summed to give the total CH_4 emitted to the atmosphere. The flow "N_2O to air from combustion" is used to generate the total N_2O emitted to the atmosphere.

All of these flows are calculated with equations that have adjustable parameters or variables. A number of these variables are specified as random variables with an associated probability distribution. Thus, all the flows are random variables. The equations used to calculate the various flows are presented in detail in sheet S1a.UP.O.CoalMOp within the F-T Jet Fuel Spreadsheet Model. The variables specified as random variables are presented in the next section.

For construction, all the input flows, output flows and GHG emissions are determined in sheet S1a.UP.C.CoalMCon. This sheet, in turn, references information in other sheets, as discussed in sheet S1a.UP.C.CoalMCon. The input flows for construction in this stage are:

- steel plate, BF (85 percent Recovery Rate)
- steel, cold rolled
- steel, hot-dip galvanized

- steel, 316 stainless cold rolled
- steel, 316 2B (80 percent recycled)
- steel, 431 stainless cold rolled
- cast iron parts
- rebar
- coppersheet
- zinc
- rubber, natural vulcanized
- PVC tubing
- asphalt
- concrete, mixed 5-0
- diesel fuel
- gasoline

The only output flow for construction is a constructed underground coal mine.

The GHG emissions are CO_2 from non-biogenic sources, CO_2 from biogenic sources (zero for this stage), CH_4, and N_2O.

The sheet includes the following additional flows to facilitate mass balance calculations for GHGs: "CO_2 to air from combustion," "CH_4 to air from combustion," and "N_2O to air from combustion." These flows, which result from the use of diesel fuel and gasoline during installation and de-installation of the coal mine, are used to generate the total CO_2, CH_4, and N_2O emitted to the atmosphere for construction activities in this stage.

All of the input flows are specified as random variables with an associated distribution. The GHG emissions result from the combustion of diesel fuel and gasoline. Both of these flows are random variables, and the GHG emissions are also random variables. The equations used to calculate the GHG emissions are presented in detail in sheet S1a.UP.C.CoalMCon within the F-T Jet Fuel Spreadsheet Model. The variables specified as random variables are presented in the next section.

4.1.1.3 Key Modeling Variables

The key variables with respect to the emissions of GHGs during the construction and operation of an underground Illinois No. 6 coal mine are presented in Table 16. For each variable the best estimate is presented along with the minimum value, maximum value, most likely value and the distribution assumed for the variable.

For many of the variables in Table 16, data were not readily available to estimate uncertainty, and/or to evaluate a most likely value. For example, the amount of electricity and diesel necessary to excavate 1 kg of coal is not known precisely. The best estimate for electricity given in Table 16 is based on data for the Galatia mine, while the best estimate for diesel is based on data for underground mines as a whole. To determine the impact that uncertainty in these values

might have on the result, a minimum and maximum range was estimated using professional judgment. The range selected for each variable varies based on factors such as physical limits, industry knowledge, and/or conservative estimates to test the significance of the variable (e.g., increase the amount of diesel fuel used per unit of coal mined by 50 percent). Similarly, for all the materials used to manufacture coal mining machinery (i.e., the variables Steel Plate through PVC Tubing in Table 16), it was assumed that the best estimate might be higher by 50 percent or lower by 10 percent. For all these variables, it was assumed the uncertainty can be characterized by a triangular distribution.

The amount of coal produced in a given year is uncertain and depends on the capacity of the mine operations, the fraction of the capacity that is actually used, and the fraction of run-of-mine coal that is useable or marketable coal. In 2005, the capacity of the Galatia mine was 2,400 tonnes/hr of run-of-mine coal. The values for the variables Fraction of Capacity that is Actually Used and Fraction of Run-of-Mine Coal that is Usable Coal are based on data for the Galatia mine from 2005 to 2007 to represent regional operations.

No information could be found on the resources required to close or de-install or decommission an underground coal mine. For this evaluation, it was assumed that a reasonable estimate for the resources (and emissions) needed for de-installation is 10 percent of the resources (and emissions) for installation of the mine. To characterize the uncertainty in this variable, it was assumed that the resource required for de-installation could be as low as 5 percent or as high as 25 percent of the resources for installation. A triangular distribution was used to characterize this uncertainty.

The amount of concrete and asphalt needed to install a coal mine is not available for the Galatia mine. Instead, data from two other new underground coal mines were obtained and used as surrogates. The values for concrete and asphalt used during mine installation are based on data for these two mines.

Table 16. Key Modeling Variables for Illinois No. 6 Coal Mining (LC Stage #1a)

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-Coal Mine Operation							
Electricity Used per kg of Useful Coal Produced	kWh/kg coal	3.31E-02	2.98E-02	3.64E-02	3.31E-02	Uniform	Assumed that electricity use is -10% to +10% of best estimate
Diesel Fuel Used per kg of Useful Coal Produced	kg dies/kg coal	2.63E-04	2.37E-04	3.94E-04	2.63E-04	Triangular	Assumed that diesel use is -10% to +50% of best estimate
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	scf/ton	150.0	120.0	180.0	150.0	Uniform	Estimated variation of +20% to -20% for low to moderate gassy mines in the Southern Illinois coal basin.
Fraction of Coal Bed Methane Captured	kg/kg	0.400	0.200	0.600	0.400	Uniform	Minimum, maximum, and best estimate from US EPA report on coal bed methane capture
Fraction of Capacity of Mine that is Actually Used	kg/kg	53.1%	50.1%	57.1%	53.6%	Uniform	Based on data from Galatia mine from 2005-2007; data for 2008 excluded because production declined due to recession
Fraction of Run-of-Mine Coal that is Usable Coal	kg/kg	54.8%	51.7%	59.9%	55.8%	Uniform	Based on data from Galatia mine from 2005-2007
CO_2 Emitted per kWh SERC Electricity Produced	kg CO_2/kWh	0.76	0.69	0.84	0.76	Triangular	Assumed that material use is -10% to +50% of best estimate
CH_4 Emitted per kWh SERC Electricity Produced	kg CH_4/kWh	8.35E-04	7.52E-04	9.19E-04	8.35E-04	Triangular	Based on data from Galatia mine from 2005-2007
N_2O Emitted per kWh SERC Electricity Produced	kg N_2O/kWh	1.01E-05	9.08E-06	1.11E-05	1.01E-05	Triangular	Based on data from Galatia mine from 2005-2007
Input Parameters-Coal Mine Construction							
Fraction of Installation Inputs and Outputs Assumed to Apply to De-Installation		0.10	0.05	0.25	0.10	Triangular	Assumed based on best engineering judgment
Diesel Fuel Used in Installation	kg	4.85E+05	4.37E+05	7.28E+05	4.85E+05	Triangular	Assumed that diesel use is -10% to +50% of best estimate
Gasoline Used in Installation	kg	5.10E+02	4.59E+02	7.65E+02	5.10E+02	Triangular	Assumed that gasoline use is -10% to +50% of best estimate

Table 16. Key Modeling Variables for Illinois No. 6 Coal Mining (LC Stage #1a) *(Cont'd)*

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-Coal Mine Construction (Cont'd)							
Steel Plate, BF (85% Recovery Rate) for Underground Coal Mine	kg/kg coal	2.35E-04	2.12E-04	3.53E-04	2.35E-04	Triangular	Assumed that material use is -10% to +50% of best estimate
Steel, Cold Rolled for Underground Coal Mine	kg/kg coal	1.46E-06	1.32E-06	2.19E-06	1.46E-06	Triangular	Assumed that material use is -10% to +50% of best estimate
Steel, Hot-dip Galvanized for Underground Coal Mine	kg/kg coal	1.45E-06	1.30E-06	2.17E-06	1.45E-06	Triangular	Assumed that material use is -10% to +50% of best estimate
Steel, 316 Stainless Cold Rolled for Underground Coal Mine	kg/kg coal	7.13E-06	6.42E-06	1.07E-05	7.13E-06	Triangular	Assumed that material use is -10% to +50% of best estimate
Steel, 316 2B (80% Recycled) for Underground Coal Mine	kg/kg coal	6.75E-08	6.08E-08	1.01E-07	6.75E-08	Triangular	Assumed that material use is -10% to +50% of best estimate
Steel, 431 Stainless Cold Rolled for Underground Coal Mine	kg/kg coal	7.13E-07	6.41E-07	1.07E-06	7.13E-07	Triangular	Assumed that material use is -10% to +50% of best estimate
Cast Iron Parts for Underground Coal Mine	kg/kg coal	3.37E-07	3.04E-07	5.06E-07	3.37E-07	Triangular	Assumed that material use is -10% to +50% of best estimate
Rebar for Underground Coal Mine	kg/kg coal	1.96E-08	1.77E-08	2.95E-08	1.96E-08	Triangular	Assumed that material use is -10% to +50% of best estimate
Coppersheet for Underground Coal Mine	kg/kg coal	8.09E-09	7.28E-09	1.21E-08	8.09E-09	Triangular	Assumed that material use is -10% to +50% of best estimate
Zinc for Underground Coal Mine	kg/kg coal	6.46E-09	5.81E-09	9.68E-09	6.46E-09	Triangular	Assumed that material use is -10% to +50% of best estimate
Rubber, Natural Vulcanized for Underground Coal Mine	kg/kg coal	4.44E-07	4.00E-07	6.66E-07	4.44E-07	Triangular	Assumed that material use is -10% to +50% of best estimate
Polyvinylchloride (PVC) Tubing	kg/kg coal	1.30E-07	1.17E-07	1.94E-07	1.30E-07	Triangular	Assumed that material use is -10% to +50% of best estimate
Asphalt for Underground Coal Mine	kg/kg coal	9.98E-04	8.98E-04	1.50E-03	9.98E-04	Triangular	Assumed that material use is -10% to +50% of best estimate
Concrete, Mixed 5-0 for Underground Coal Mine	kg/kg coal	4.54E-05	4.09E-05	6.82E-05	4.54E-05	Triangular	Assumed that material use is -10% to +50% of best estimate

The amount of methane contained in a coal bed, and released during the coal mining process, is a key component of the upstream GHG emissions for any process using coal as a feedstock. The amount of coal bed methane (CBM) in a formation is highly variable, and depends on a wide range of geologic and technological variables, such as coal type, depth, and mining method.

Southern Illinois was chosen as the source of coal for this system, specifically Illinois No. 6 coal from underground longwall mines. The US EPA defines "gassy" coal mines as those having average methane emissions of over 71 scf/ton (US EPA, 2009e). Underground mines in Southern Illinois that mine Illinois No. 6 coal and Illinois No. 5 (a slightly deeper seam than Illinois No. 6 and also referred to as Springfield No. 5) have been reported by Tarka (2010) to consist of a range of low gassy to high gassy coal bed methane content, with a typical range of 50 to 150 standard cubic feet of methane per short ton of coal (scf CH_4/ton coal). This range only accounts for 50 percent of the contribution to coal mine methane emissions. The other half of the methane emission is due to gas in the rock strata surrounding the coal being liberated into the mine void. A low- to moderate-gassy mine profile with an average value of 150 scf CH_4/ton coal (with a +/- 20 percent uniform distribution of uncertainty) was selected and applied within this study to represent each scenario under a carbon constrained environment. Detailed analysis of Illinois basin coal methane profiles are provided in Tarka (2010).Methane emissions can be reduced at gassy mines using methane capture and combustion technology. In the system considered in this study, 40 percent of the methane is assumed to be captured and converted to CO_2. The 40 percent value is based on information contained in a report by the US EPA (2009), which indicates that coal bed methane capture systems recover 20 percent to 60 percent of all coal bed methane that could be released by mining operations, with a best estimate of 40 percent. The decision to capture methane at a particular mine is primarily an economic one, and so there is not a single level of methane above which capture would occur, and below which it would not. For this reason, and the relative gassiness of the Southern Illinois formations, an assumption is made to convert 40 percent of all the CBM to CO_2.

4.1.2 Data Quality Assessment

The results of unit process data quality evaluation for Stage #1a are provided in Table 17. Data quality indicators and life cycle significance determinations are listed for each unit process included in the model of this stage. The life cycle significance values shown for the collated construction process (second row of the table below) represents the lowest quality indicators from all lower level processes combined. Additional uncertainty may be added by data required to assemble subprocesses.

Analysis of the life cycle significance of processes shows that the composite construction process for the Illinois No. 6 Bituminous Coal Mine, and thus all subprocesses, are below the significance threshold for the jet fuel production life cycle. This result determines that though DQI scores are below the quality requirement of 1-2, the data used for these processes is acceptable because of the low significance.

The coal mine operation process, at 1.01 percent of the base case life cycle significance, is slightly above the significance threshold. In addition, the DQI for this process is below the required quality rating. Therefore, low-quality data parameters within the coal mine operation process are included in the cumulative sensitivity analysis for this study. Results of the cumulative analysis can be found in **Section 10**. Low-quality significant data used in modeling the operation of the coal mine include the assumption that 40 percent of coal bed methane is

captured. Other low data quality scores originate from the geographic and temporal representativeness of GHGs from diesel combusted in construction vehicles, and the temporal representativeness of data used to determine diesel consumption per kg of coal produced.

Table 17. Illinois No. 6 Coal Mining (LC Stage #1a) Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Life Cycle Significance of Process (%)
1	Illinois No. 6 Underground Bituminous Coal Mine Operation	3,3,4,3,3	1.01%
1	Illinois No. 6 Underground Bituminous Coal Mine Construction	3,3,4,3,3	0.02%

4.1.3 Results

This section presents the life cycle GHG emissions for Stage 1a. The first section presents the deterministic results, where deterministic means that the results are based on setting each variable that is uncertain to its best estimate value (see Table 16 for a list of key variables and their uncertainty). The second section presents the range in GHG emissions when variables that are uncertain are allowed to be varied in a probabilistic simulation, using a Monte Carlo analysis. The third section presents the influence of each uncertain variable on GHG emissions when the uncertain variables are systematically varied in a sensitivity analysis.

The deterministic results for Stage #1a are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S1a.Summ, which presents the input flows, output flows (products and co-products) and GHG emissions for this stage. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the functional unit. The operations unit process references are in sheet S1a.UP.O.CoalMOp and the construction unit process references are in sheet S1a.UP.C.CoalMCon. The GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are also presented in this sheet.

4.1.3.1 Deterministic Greenhouse Gas Emissions

The results are deterministic in that the results are based on setting each variable that is uncertain to its best estimate value. Table 18 presents the life cycle GHG emissions for Stage 1a in terms of the reference flow for this stage, which is 1 kg of coal ready for transport. This table presents the total emissions of 1) non-biogenic carbon dioxide from operation and construction, 2) biogenic carbon dioxide from operation and construction, 3) methane from operation and construction, 4) nitrous oxide from operation and construction, and 5) other GHGs from operation and construction. This last category, other GHGs, captures emissions from GHGs other than carbon dioxide, methane or nitrous oxide, or emissions that are expressed in carbon dioxide equivalents and cannot be differentiated into the primary GHGs. The second column in the table presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the 100-year IPCC 2007, IPCC 2001, and IPCC 1996 estimates, respectively.

As indicated in Table 18, operation of the coal mine contributes far more to life cycle GHG emissions than do construction activities (which include installation and de-installation of the coal mine). Operations account for over 99 percent of the total life cycle GHG emissions for LC Stage 1a, due in large part to emissions of coal bed methane.

There are significant emissions of methane in this stage, even with a coal bed methane capture system operating. Methane accounts for 57 percent to 62 percent of the total CO_2e GHG emissions, depending on which set of global warming potentials is used.

Table 18. LC Stage #1a GHG Emissions (per kg Coal Ready for Transport)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/kg coal)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg coal) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg coal) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg coal) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	30.0	30.0	30.0	30.0
Non-biogenic CO_2 – Construction	0.4	0.4	0.4	0.4
Non-biogenic CO_2 – Subtotal	30.0	30.0	30.0	30.0
Biogenic CO_2 – Operation	0.0	0.0	0.0	0.0
Biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Biogenic CO_2 – Subtotal	0.0	0.0	0.0	0.0
CH_4 – Operation	1.90	48.0	44.0	40.0
CH_4 – Construction	0.00	0.0	0.0	0.0
CH_4 – Subtotal	1.90	48.0	44.0	40.0
N_2O – Operation	0.0004	0.1	0.1	0.1
N_2O – Construction	0.0000	0.0	0.0	0.0
N_2O – Subtotal	0.0004	0.1	0.1	0.1
Other GHG – Operation		0.0	0.0	0.0
Other GHG – Construction		0.0	0.0	0.0
Other GHG – Subtotal		0.0	0.0	0.0
Operation – Total		78.0	74.0	70.0
Construction– Total		0.4	0.4	0.4
Grand Total		78.0	74.0	70.0

Note: Subtotals and totals may not sum exactly due to rounding.

4.1.3.2 Probabilistic Uncertainty Analysis

In an attempt to quantify the influence of uncertainty in the key variables presented in Table 16 on the calculated GHG emissions, probabilistic simulations were performed. The modeled life cycle GHG emissions have a number of variables that are considered uncertain (see Table 16).

In this evaluation, probabilistic simulations were performed for total life cycle GHG emissions using the IPCC 2007 global warming potentials. CO_2 equivalent emissions were calculated relative to the stage reference flow of 1 kg coal ready for transport. Table 19 presents the statistics for the CO_2e emissions developed from the simulations. Figure 11 presents the cumulative distribution and probability density function for CO_2 equivalent emissions relative to the LC Stage #1a reference flow. In Figure 11, the vertical scale on the left is for the probability density function and the vertical scale on the right is for the cumulative distribution.

The CO_2 equivalent emissions relative to the reference flow range from 56 to 110 g CO_2e/kg coal, with a median value of 78 g CO_2e/kg coal, a mean of 78 g CO_2e/kg coal, and a standard deviation of 10 g CO_2e/kg coal. Eighty percent of the distribution lies between 70 and 93 g CO_2e/kg coal, and the middle fifty percent of the distribution lies between 71 and 86 g CO_2e/kg coal, reflecting the degree of uncertainty contained in the methane emissions estimates presented in this study (Table 19).

Table 19. LC Stage #1a: Probabilistic Uncertainty Analysis; Statistics for CO_2e Emissions

Statistical Parameter	Mass of GHG Emitted to Atmosphere (g CO_2e/kg coal) (IPCC 2007 GWP)
Minimum	56
10%	70
25%	71
Median (50%)	78
75%	86
90%	93
Maximum	110
Mean	78
Mode	80
Stand. Deviation	10

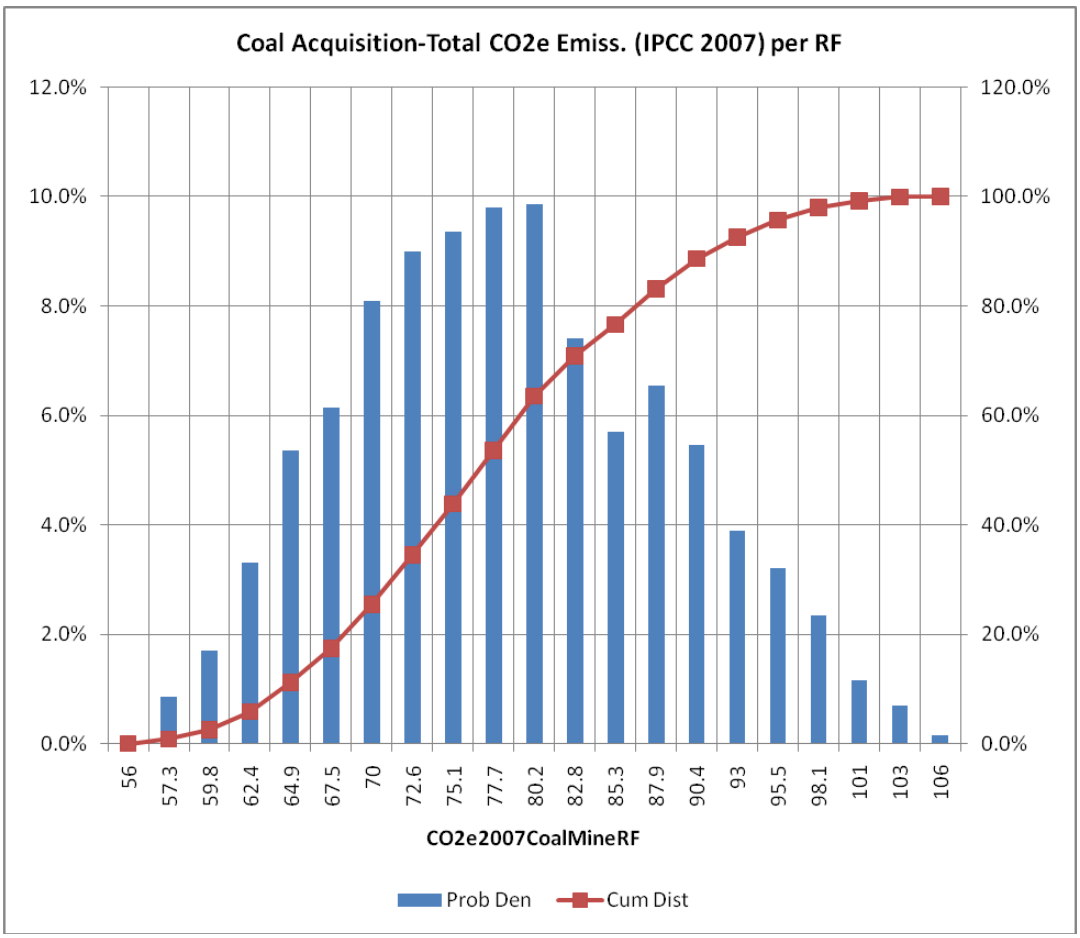


Figure 11. LC Stage #1a Probability Density Function and Cumulative Distribution of CO_2e Emissions (using IPCC, 2007 GWP) (per kg Coal Ready for Transport)

4.1.3.3 Sensitivity Analysis

In the sensitivity analysis, the total CO_2e emission using the IPCC 2007 global warming potentials was calculated for each key variable. Table 20 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions when all other variables are held at their most likely value. The absolute difference for each key variable is also shown, and key variables are listed from highest to lowest based on their absolute difference.

The variable that has the most influence is the amount of coal bed methane generated, followed by the fraction of coal bed methane captured. The next variable with the most influence is the amount of electricity used per kg of coal extracted. All other key variables have a negligible influence on total CO_2e emissions. This same result is presented graphically in the tornado chart presented in Figure 12. The tornado chart clearly indicates that the amount of coal bed methane generated and the fraction of coal bed methane captured are the most influential of the key variables; other variables are shown, but are very small compared with these three key variables. The fact that the key variables associated with construction (e.g., all the variables associated with mass of materials needed to manufacture coal mining equipment or install a coal mine) have little influence on the CO_2e emissions is consistent with the deterministic results, which indicate that construction emissions are responsible for less than 1 percent of the total CO_2e emissions.

Table 20. Sensitivity Analysis Results (Using IPCC 2007 GWP) (g CO_2e/kg Coal Ready for Transport)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/kg coal)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap	kg/kg	0.4	0.2	0.6	92	64	28
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton	scf/ton	150	120	180	68	88	20
Electricity Used per kg of Useful Coal Produced	Electricity_kg	kWh/kg coal	0.033	0.03	0.036	76	81	5.2
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg	kg dies/kg coal	0.00026	0.00024	0.00039	78	79	0.63
Steel Plate, BF (85% Recovery Rate) for Underground Coal Mine	Stl_Plt_BF85_Coal_kg	kg/kg coal	0.00024	0.00021	0.00035	78	78	0.17
Steel, 316 Stainless Cold Rolled for Underground Coal Mine	Stl_CR316_Coal_kg	kg/kg coal	0.0000071	0.0000064	0.000011	78	78	0.023
Asphalt for Underground Coal Mine	Asphalt_Coal_kg	kg/kg coal	0.001	0.0009	0.0015	78	78	0.012
Diesel Fuel Used in Installation	Dies_Used_In	kg	490000	440000	730000	78	78	0.0071
Concrete, Mixed 5-0 for Underground Coal Mine	Concrete_5_0_Coal_kg	kg/kg coal	0.000045	0.000041	0.000068	78	78	0.0038
Steel, Cold Rolled for Underground Coal Mine	Stl_CRoll_Coal_kg	kg/kg coal	0.0000015	0.0000013	0.0000022	78	78	0.0025
Fraction of Installation Inputs and Outputs Assumed to Apply to De-Installation	DeIn_Frac		0.1	0.05	0.25	78	78	0.0021
Steel, 431 Stainless Cold Rolled for Underground Coal Mine	Stl_CR431_Coal_kg	kg/kg coal	0.00000071	0.00000064	0.0000011	78	78	0.002
Fraction of Run-of-Mine Coal that is Usable Coal	Frac_Coal	kg/kg	0.55	0.52	0.6	78	78	0.0018
Fraction of Capacity of Mine that is Actually Used	Frac_Used	kg/kg	0.53	0.5	0.57	78	78	0.0016
Polyvinylchloride (PVC) Tubing	PVC_Tube1_Coal_kg	kg/kg coal	0.00000013	0.00000012	0.00000019	78	78	0.00075
Steel, 316 2B (80% Recycled) for Underground Coal Mine	Stl_3162B_80_Coal_kg	kg/kg coal	0.000000068	0.000000061	0.0000001	78	78	0.00022
Cast Iron Parts for Underground Coal Mine	Cst_Iron_Pt1_Coal_kg	kg/kg coal	0.00000034	0.0000003	0.00000051	78	78	0.00021

Table 20. Sensitivity Analysis Results (Using IPCC 2007 GWP) (g CO_2e/kg Coal Ready for Transport) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/kg coal)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Rubber, Natural Vulcanized for Underground Coal Mine	Rub_NVulc_Coal_kg	kg/kg coal	0.00000044	0.0000004	0.00000067	78	78	0.00019
Coppersheet for Underground Coal Mine	CopSht1_Coal_kg	kg/kg coal	8.1E-09	7.3E-09	0.00000001 2	78	78	0.000033
Zinc for Underground Coal Mine	Zinc1_Coal_kg	kg/kg coal	6.5E-09	5.8E-09	9.7E-09	78	78	0.000019
Rebar for Underground Coal Mine	Rebar1_Coal_kg	kg/kg coal	0.00000002	0.00000001 8	0.00000002 9	78	78	0.000011
Gasoline Used in Installation	Gas_Used_In	kg	510	460	760	78	78	0.0000075
Steel, Hot-dip Galvanized for Underground Coal Mine	Stl_Galv_Coal_kg	kg/kg coal	0.0000014	0.0000013	0.0000022	78	78	0

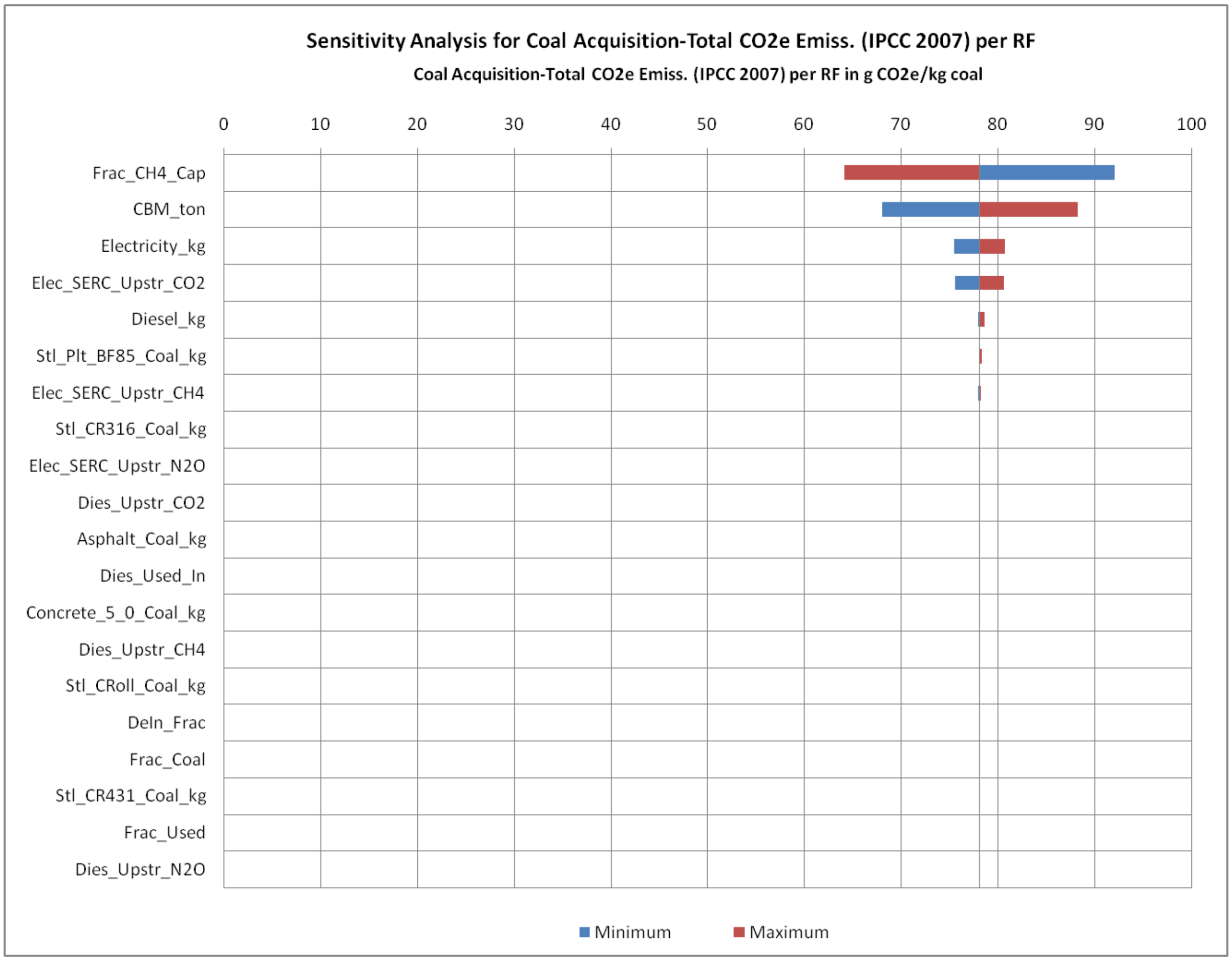


Figure 12. LC Stage #1a Sensitivity Analysis Results (Using IPCC 2007 GWP) (g CO_2e per kg Coal Ready for Transport)

4.2 Switchgrass Production (LC Stage #1b)

LC Stage #1b includes agricultural production of switchgrass on a farm, starting with the establishment and preparation of land area used for farming, then seeding, field maintenance during growth, harvest of the switchgrass, and storage of the harvested switchgrass until transport to the CBTL facility under subsequent LC Stages. The boundary ends just prior to transportation of the harvested material offsite by truck under LC Stage #2b, where LC Stage #2b is the process of transporting the switchgrass by truck to the CBTL facility (LC Stage #3a).

Alternate switchgrass primary production pathways are included in this LC Stage to provide a continuous supply of up to 3,462 dry tonnes switchgrass/day to the CBTL facility as rectangular bales that have been stored in a shed, round bales that have been in covered storage, or twine-wrapped round bales that have been stored outside while elevated. The equipment and process used for each of these alternates varies, as discussed below.

4.2.1 Modeling Approach and Data Sources

The primary production data here are intended to represent switchgrass produced in the Chariton Valley (Northern Missouri/ Southern Iowa, USA) as shown in Figure 4. Establishment of land is assumed to be on pasture and cropland in both states as presented in Table 21 based on estimates by EneGis (2010). The switchgrass, assumed to be the variety Cave-in-Rock, is a perennial warm-season switchgrass assumed to be 46.96 percent carbon by mass. Table 22 lists key assumptions made in modeling switchgrass production with emissions estimates limited to CO_2, CH_4, and N_2O.

Switchgrass production includes establishment of land on pasture and cropland (apportioned as shown in Table 21), reseeding, field maintenance, harvest, storage, and transport to provide a continuous supply of up to 3,462 dry tonnes switchgrass/day to the CBTL facility over 30 years (the specific supply rate depends upon the CBTL facility scenario choice made under LC Stage #3a of the F-T Jet Fuel Spreadsheet Model, and as documented in **Section 6** of this report). The primary inputs are consumable materials (e.g., fertilizers), electricity and fuels (e.g., for farm equipment and transport), equipment and storage facility construction, and waste management. Note that only secondary emissions of nitrogen fertilizer (from its production and transport) are accounted for within this LC Stage. Direct emissions associated with application of nitrogen fertilizers, including offgassing or other chemical releases, are accounted for separately, in LC Stage #1c. Primary and secondary emissions for other (non-nitrogen) fertilizers are considered within this LC Stage. The outputs are the switchgrass at the ready for transport and select air emissions (CO_2, CO, NMVOC, CH_4, and N_2O) which are ultimately used to estimate the contribution to climate change. The reference flow is a unit mass of switchgrass.

Table 21. Cropland and Pastureland for Switchgrass Production in the Chariton Valley (Enegis, 2010)

Percent of Production Area	Land Type
65%	Converted from pastureland in Missouri
11%	Converted from pastureland in Iowa
17%	Converted from cropland in Missouri
7%	Converted from cropland in Iowa

Table 22. Key Assumptions for Switchgrass Production

Primary Subject	Assumption	Basis	Source
Switchgrass type	*Panicum virgatum, L.*	Native to the region	(Duffy & Nanho, 2002)
Cultivation location	Chariton Valley (Southern Illinois and Northern Missouri)	Cultivation location of switchgrass	(Duffy & Nanho, 2002)
Yield	10.5 dry tonnes/ha per year (4.7 dry tons/acre per year)	The mass produced per area before harvest and storage losses are considered	(Duffy & Nanho, 2002), (Rotz, 1995), (Rotz, 2006)
Cultivation period	30 years	Assumption	As model input
Establishment, reseeding, maintenance, harvest, and storage methods	Various (see Table 23)	Extended from those suggested by Duffy and Nanho, Bransby, et al., and Rotz	(Duffy & Nanho, 2002) , (Bransby, 2005), (Rotz, 2001)

Switchgrass production is modeled as a 5-step process:

1. **Establishment of land** on pasture and/or cropland including clearing, preparation, and seeding in a manner that does not foster competition by other grasses;
2. **Reseeding** during select spring seasons and following frosts;
3. **Maintenance** of the field including annual applications of fertilizers and other chemicals;
4. **Harvest** of the switchgrass including mowing, conditioning, pickup and raking, and baling; and
5. **Storage** of the switchgrass in the vicinity of the farm and to allow for a continuous feedstock supply for energy conversion.

Given these steps, Figure 13 presents the data collection process for the production of switchgrass. The process begins based on the identification of equipment to be used. Assuming further processing at the CBTL facility (e.g., unbailing, additional grinding) are a part of the conversion facility operations, equipment sets for establishment through storage are combined using market shares (representing the percent of each set assumed to be applied) to prepare data in 3 scenarios as presented in Table 23. In Table 23**,** the equipment sets for establishment through maintenance are extended from Bransby, et al. (Bransby, 2005) to include a wider variety of seeding and cultivation options, the harvest sets are represented as three baling options modified from Rotz[3] (Rotz, 2001), and storage options were selected from those described by Rotz and Shinners (Rotz, 2006).

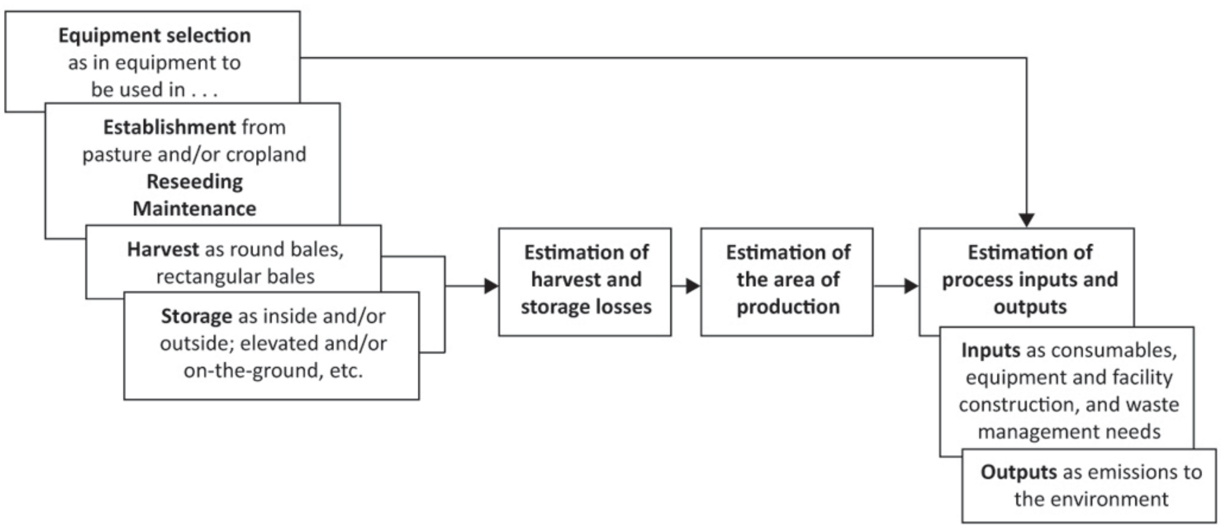


Figure 13. Data Collection Process for Switchgrass Production

[3] Tedding has been omitted from the scenarios suggested in (Rotz, 2006) and is assumed not to be included here. Also small-bale use has declined, but remains a viable package for equestrian and landscape markets (Rotz, 2006).

For the equipment sets shown in Figure 13, the ***productive yield*** (the mass produced per area before harvest and storage losses are considered) for the Chariton Valley switchgrass is estimated as 10.5 dry tonnes/ha per year (4.7 dry tons/acre per year). This value was estimated starting from the expected yield of 9.0 tonne/ ha per year (4.0 tons/acre per year) for switchgrass harvested as rectangular bales[4] (for the yield going into storage) used by Duffy and Nanhou (Duffy, 2002) combined with the cumulative estimation of losses as described by Rotz (1995) for respiration during field drying, mowing and conditioning, pickup, raking, and baling. The parameters used in the estimation of the losses based on the relationships in Rotz (1995) are presented in Table 24 with the field curing time estimated as described by Hill (1976) for hay and assuming no rainfall during drying. Then, given the estimated productive yield of 10.5 dry tonnes/ha per year, the losses for each scenario were estimated for each equipment set to include storage losses based on data presented by Rotz and Shinners (Rotz, 2006).

Table 23. Equipment Sets and Market Shares

Process	Description	Rectangular Bales, Shed Storage	Round Bales, Tarp Covered	Round Bales, Twine Wrap, Elevated
Establishment from Pasture	Establishment from pastureland; mowing and roundup; no-till drill seed; fertilizer and herbicide/pesticide application	33%	33%	33%
	Plow and disc; drill seed; fertilizer and herbicide/pesticide application	33%	33%	33%
	Disc and cultipak; drill seed; fertilizer and herbicide/pesticide applications	33%	33%	33%
Establishment from Cropland	Disc and harrow; drill seed; fertilizer and herbicide/pesticide application	50%	50%	50%
	No-till drill seed; fertilizer and herbicide/pesticide application	50%	50%	50%
Reseeding	Disc and harrow; drill seed; fertilizer and herbicide/pesticide application	50%	50%	50%
	No-till drill seed; fertilizer and herbicide/pesticide application	50%	50%	50%
Maintenance	Fertilizer and herbicide/pesticide application	50%	50%	50%
	Fertilizer application	50%	50%	50%
Harvest	Large rectangular bale systems: mower-conditioner (4.3 – 4.9m wide) or self-propelled swather, rake, midsize-larger baler, bale mover	100%	N/A	N/A
	Round bale systems: mower-conditioner (2.7–4.3m wide), rake, baler, bale mover	N/A	100%	100%

[4] Assuming establishment from pastureland as mowing and Roundup application, no-till drill seed, fertilizer and herbicide application (as in Duffy and Nanhou's Scenario 7); establishment from cropland and reseeding as disc and harrow, drill seed, fertilizer and herbicide application (as in Duffy and Nanhou's Scenario 4); maintenance as fertilizer and herbicide application; and harvest as large rectangular bales to match Duffy and Nanhou's cost model.

Table 23. Equipment Sets and Market Shares *(Cont'd)*

Process	Description	Rectangular Bales, Shed Storage	Round Bales, Tarp Covered	Round Bales, Twine Wrap, Elevated
Storage	Rectangular bales, shed	100%	N/A	N/A
	Round bales, tarp covered stacks	N/A	100%	N/A
	Round bales, twine wrap, elevated	N/A	N/A	100%
Transport	Plow and disc; drill seed; fertilizer and herbicide/pesticide application	33%	33%	33%

Table 24. Loss Estimation Parameters*

Parameter	Rectangular Bales	Round Bales
Initial crop moisture content	78% (75-80%)[5]	
Moisture content at pick-up	50%[5]	
Moisture content at raking	35%[5]	
Final crop moisture content	15% (14-18%)[6]	15%[6]
Field curing time (hours)	134 (125-142)	114 (105-122)
Average diurnal temperature (deg C)	19[7]	
Average saturation vapor pressure deficit (VPD, mbar)	5.0[8]	
Average wind speed (km/hr)	9.0[7]	
Solar radiation (Langleys/day)	389[9]	
Total daily pan evaporation (EVAP, mm)	4.1	

* Parenthetical values show the minimum and maximum cases respectively

Table 25. Farm Yield and Area Summary, for Annual Removal of Switchgrass from Storage

Parameter	Units	Rectangular Bales, Shed Storage		Round Bales, Covered Storage		Round Bales, Elevated Outside Storage	
		Best Estimate	Range (best to worst case)	Best Estimate	Range (best to worst case)	Best Estimate	Range (best to worst case)
Mass of production needed to cover dry matter loss	Dry tonnes switchgrass / year	1.7E+06	1.6E+06 to 1.8E+06	1.7E+06	1.6E+06 to 1.8E+06	1.8E+06	1.7E+06 to 1.9E+06
Farmed area needed to cover dry matter loss	Hectares	1.6E+05	1.5E+05 to 1.7E+05	1.6E+05	1.6E+05 to 1.7E+05	1.7E+05	1.6E+05 to 1.8E+05
Net yield	Dry tonnes/ ha/ year	8.7	9.2 to 8.1	8.7	9.1 to 8.2	8.4	8.7 to 7.9
Storage area	Hectares	1.6E+03	1.1E+03 to 2.5E+03	5.8E+03	4.2E+03 to 9.2E+03	6.0E+03	4.4E+03 to 9.6E+03
Farm area = farmed area + storage areas	Hectares	1.6E+05	1.5E+05 to 1.8E+05	1.7E+05	1.6E+05 to 1.8E+05	1.7E+05	1.7E+05 to 1.9E+05

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[5] Based on data from Undersander at http://www.uwex.edu/ces/forage/pubs/drying_forage.pdf
[6] As the safe baling moisture content defined by Collins and Owens (Collins, 1995), intended to avoid spontaneous combustion.
[7] Data represent the average for September 5-19, 2009 (a period of no rain) for the Kirksville Airport in Missouri and from http://www.wunderground.com
[8] From the standard psychrometric data in ASAE D271
[9] For September and for the study region, representing 4-5 kWh/m^2/day from http://rredc.nrel.gov/solar/

The resulting cumulative losses through storage are estimated at from 13-26 percent for rectangular bales stored in a shed, 13-24 percent for round tarp covered bales, and 18-28 percent for round twine wrapped elevated bales with 19 percent, 18 percent, and 22 percent used respectively as the best estimate values. The resulting ***net yield*** (the mass produced per area after harvest and storage losses are considered) for each scenario is estimated at a range of 7.9-9.2 percent dry tonnes per ha per year, as presented in Table 25. Table 25 also presents the estimated farmed area at a range of 154 – 178 thousand ha, and the estimated area for switchgrass storage based on the methods presented by Holmes (2003).

Based on the farmed area, data for the use of seed, fertilizers, herbicides, lime, and round bale tarps are from Duffy and Nanhou (Duffy, 2002) for establishment through field maintenance:

- **Seed:** The seeding rate for establishment and frost seeding is 6.72 kg/ha (6 lb/acre) of pure live seed and spring reseeded uses 5.6 kg/ha (5 lb/acre).
- **Fertilizers:** During the establishment year, it is assumed that phosphorus is applied at a rate of 33.6 kg P/ha (30 lbs P/acre) and potassium is applied at a rate of 44.8 kg K/ha (40 lbs K/acre). To avoid competition between the new switchgrass stand and weeds, no nitrogen is assumed to be applied in the establishment year. During production years, phosphorus and potassium fertilization varies by yield to compensate for the removal rate in potassium and phosphorus. With each tonne of switchgrass harvested, it is assumed that 0.97 kg of P_2O_5 and 11.41kg of K_2O is used (1.94 pounds of P_2O_5 and 22.8 pounds of K_2O per ton of switchgrass) and that the relationship between the rates of P and K removal with switchgrass yield is linear. Also during production, nitrogen fertilizer is applied at 112 kg N/ha (100 lb N/acre).
- **Herbicides:** Atrazine, 2,4 D, and Roundup™ are used for weed control at rates of 3.5, 1.75, and 4.67 L/ha (0.37, 0.19, and 0.50 gal/acre), respectively, for land establishment on pastureland. Atrazine and 2,4 D are used at rates of 3.5 and 1.75 L/ha (0.37 and 0.19 gal/acre), respectively, for land establishment on cropland.
- **Lime:** Although lime needs vary by field, it is assumed that over the life of the switchgrass stand lime would have to be applied once at a rate of 6.72 tonnes/ha (3 tons/acre).
- **Round bale tarps.** The use of bale tarps for the first round bale scenario is estimated assuming stacks of 4 bales as described by Huhnke (undated) as 6 mil thick polyethylene sheets with a 3-year life.

Also, transport of fertilizers, herbicides, and lime to the farm is estimated on a per kg-km basis as presented in Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation Model (GREET) (ANL, 2009), with seed and tarp transport assumed to be transported 80 km by truck.

For lime application, CO_2 emissions are estimated using default emission factors of 0.12 and 0.13 kg C/kg lime applied to represent limestone and dolomite, respectively, with a best estimate value of 0.125 kg C/kg lime applied. CO_2 emissions from urea application are estimated assuming 47 percent of the nitrogen is applied as urea (as in GREET) with emission factors of 0.10 – 0.20 kg C/ kg urea with 0.20 used as the best estimate value. Direct GHG emissions associated with the application of nitrogen fertilizers, including N_2O volatization emissions, are addressed under LC Stage #1c.

Equipment requirements, fuel and lubricant use, and related emissions are estimated on the basis of the operating time for the farmed area. The hours of operation per area are estimated as a function of the number of equipment passes (presented in Table 26), the field speed, swath width, and field efficiency using the ranges of equipment data within Lazarus and Bransby, et al. (Lazarus, 2009;Bransby,et al., 2005). The fuel use is assumed to be 0.14 – 0.17 L/hp-hr for disk equipment and 0.17 L/hp-hr for all other, with lubricant use estimated as 10 percent of the fuel use. The results are presented in Table 27. Results for use of consumables, including fertilizers, pesticides, lime, as well as diesel and waste management values, are shown in Table 28, while required equipment is shown in Table 29, and emissions associated with biomass storage at farm-located storage facilities are shown in Table 30.

Table 26. Equipment Passes Required, by Equipment Set per Action

Procedure	Equipment Set	Cultipack	Disk	Drill	Fert & herb application*	Harrow	Mow	No-till drill	Plow-disk
Establishment from pasture	Mowing and Roundup; no-till drill seed; fertilizer and herbicide application				n		1	1	
	Plow and disc; drill seed; fertilizer and herbicide application			1	n				1
	Disc and cultipack; drill seed; fertilizer and herbicide application	1	2	1	n				
Establishment from cropland	Disc and harrow; drill seed; fertilizer and herbicide application		2	1	n	1			
	No-till drill seed; fertilizer and herbicide application				n			1	
Reseeding	Disc and harrow; drill seed; fertilizer and herbicide application		2	1	n	1			
	No-till drill seed; fertilizer and herbicide application				n			1	
Maintenance	Fertilizer and herbicide application				n				
	Fertilizer application				n				

* n= the number of farm chemicals (e.g., fertilizers, herbicides, etc.), assumed to be separately applied

Resource use and emissions include the annual portion of establishment and reseeding as well as field maintenance, harvest, storage, and transport to provide a continuous daily supply to the CBTL facility as rectangular and round bales. In general, the three types of bales are found to be very similar, driven by similarities in net yield. For the inputs, differences between the bale types lie in the storage area required (round bales require more storage space than rectangular), in the use and waste management of bale covers (assumed to have a life of 3 years), in the use of bale-type specific equipment (e.g., the use of rectangular or round balers and bale movers), and in the overall productive areas needed.

Table 27. Switchgrass Production Equipment Requirements and Fuel Usage

Equipment	Diesel Use Per ha Per Time Over (L)				Expected Years Owned				Hectares Per Year				Units Per Year Per Hectare			
	Best Estimate	Range (best to worst case)			Best Estimate	Range (best to worst case)			Best Estimate	Range (best to worst case)			Best Estimate	Range (best to worst case)		
Baler, rectangular	4.6E+00	3.1E+00	to	6.2E+00	6	5	to	7	4.7E+02	2.6E+02	to	6.7E+02	3.5E-04	7.6E-04	to	2.1E-04
Baler, round	3.3E+00	2.2E+00	to	4.4E+00	12	10	to	14	9.6E+02	5.2E+02	to	1.4E+03	8.7E-05	1.9E-04	to	5.2E-05
Bale mover, rectangular	8.8E+00	6.0E+00	to	1.2E+01	12	10	to	14	6.2E+02	3.4E+02	to	8.8E+02	1.4E-04	2.9E-04	to	8.1E-05
Bale mover, round	7.9E+00	5.4E+00	to	1.1E+01	12	10	to	14	6.8E+02	3.7E+02	to	9.8E+02	1.2E-04	2.6E-04	to	7.3E-05
Bale, wrap	6.0E+00	1.7E+00	to	1.2E+01	10	6	to	12	6.9E+02	1.5E+02	to	9.6E+02	1.5E-04	1.1E-03	to	8.7E-05
Cultipacker	4.6E+00	3.1E+00	to	6.1E+00	30	26	to	35	1.0E+02	5.5E+01	to	1.4E+02	3.3E-04	7.1E-04	to	2.0E-04
Disk	6.6E+00	3.9E+00	to	7.9E+00	11	10	to	12	3.7E+02	2.0E+02	to	5.3E+02	2.4E-04	4.9E-04	to	1.6E-04
Drill	5.0E+00	4.0E+00	to	6.1E+00	12	12	to	13	1.9E+02	1.0E+02	to	2.4E+02	4.4E-04	8.0E-04	to	3.3E-04
Fertilizer and herbicide application	3.7E+00	2.8E+00	to	5.9E+00	11	10	to	12	3.0E+02	1.6E+02	to	5.2E+02	3.1E-04	6.1E-04	to	1.6E-04
Harrow	2.6E+00	1.0E+00	to	4.2E+00	12	10	to	14	7.8E+02	4.2E+02	to	1.1E+03	1.1E-04	2.3E-04	to	6.4E-05
Mower	4.3E+00	2.8E+00	to	5.7E+00	12	10	to	14	2.2E+02	1.2E+02	to	3.3E+02	3.7E-04	8.3E-04	to	2.2E-04
Mower-conditioner (2.7–4.3m wide)	4.0E+00	3.5E+00	to	4.7E+00	12	10	to	14	2.1E+02	1.1E+02	to	3.0E+02	4.0E-04	8.5E-04	to	2.4E-04
Mower-conditioner (4.3 – 4.9m wide) or self propelled swather	3.7E+00	3.6E+00	to	3.7E+00	12	10	to	14	2.4E+02	1.3E+02	to	3.4E+02	3.5E-04	7.6E-04	to	2.1E-04
No-till drill	7.9E+00	6.5E+00	to	8.8E+00	12	12	to	13	2.7E+02	1.9E+02	to	4.1E+02	3.0E-04	4.4E-04	to	1.9E-04
Plow-disk	9.1E+00	8.9E+00	to	9.2E+00	12	10	to	14	3.4E+02	1.9E+02	to	4.9E+02	2.4E-04	5.2E-04	to	1.4E-04
Rake	1.7E+00	6.3E-01	to	2.7E+00	12	12	to	12	5.7E+02	2.8E+02	to	8.5E+02	1.5E-04	2.9E-04	to	9.8E-05

Table 28. Switchgrass Production: Consumables

Input	Units	Rectangular bales, shed storage				Round bales, tarp covered				Round bales, net wrapped elevated			
		Best Estimate	Range (best to worst case)			Best Estimate	Range (best to worst case)			Best Estimate	Range (best to worst case)		
Fertilizer as nitrogen	kg	1.8E+07	1.7E+07	to	1.9E+07	1.8E+07	1.7E+07	to	1.9E+07	1.9E+07	1.8E+07	to	2.0E+07
Fertilizer as phosphorous	kg	1.2E+06	1.2E+06	to	1.2E+06	1.2E+06	1.2E+06	to	1.2E+06	1.2E+06	1.2E+06	to	1.3E+06
Fertilizer as potassium	kg	1.5E+07	1.4E+07	to	1.4E+07	1.4E+07	1.5E+07	to	1.4E+07	1.5E+07	1.5E+07	to	1.5E+07
Atrazine	Liter	3.4E+05	3.3E+05	to	3.7E+05	3.4E+05	3.3E+05	to	3.6E+05	3.6E+05	3.4E+05	to	3.8E+05
2,4-D amine	Liter	1.7E+05	1.6E+05	to	1.8E+05	1.7E+05	1.7E+05	to	1.8E+05	1.8E+05	1.7E+05	to	1.9E+05
Roundup	Liter	6.0E+03	5.7E+03	to	6.5E+03	6.0E+03	5.8E+03	to	6.4E+03	6.2E+03	6.0E+03	to	6.6E+03
Lime	kg	3.6E+07	3.4E+07	to	3.9E+07	3.6E+07	3.5E+07	to	3.8E+07	3.8E+07	3.6E+07	to	4.0E+07
Seeds	kg	1.1E+05	1.0E+05	to	1.2E+05	1.1E+05	1.0E+05	to	1.2E+05	1.1E+05	1.1E+05	to	1.2E+05
Round bale tarp	m^2	N/A	N/A	to	N/A	1.0E+06	4.0E+05	to	2.9E+06	N/A	N/A	to	N/A
Transport, by ocean tanker	Tkm	3.0E+08	2.9E+08	to	3.1E+08	3.0E+08	2.9E+08	to	3.0E+08	3.1E+08	3.0E+08	to	3.2E+08
Transport, by barge	Tkm	3.2E+07	3.1E+07	to	3.3E+07	3.1E+07	3.1E+07	to	3.2E+07	3.3E+07	3.2E+07	to	3.4E+07
Transport, by diesel rail	Tkm	5.9E+07	5.7E+07	to	6.1E+07	5.9E+07	5.8E+07	to	6.1E+07	6.1E+07	6.0E+07	to	6.3E+07
Transport, by truck	Tkm	9.2E+06	8.9E+06	to	9.7E+06	9.2E+06	9.0E+06	to	9.6E+06	9.6E+06	9.3E+06	to	9.9E+06
Diesel fuel	liter	4.4E+06	3.3E+06	to	5.9E+06	4.1E+06	3.0E+06	to	5.5E+06	4.3E+06	3.1E+06	to	5.7E+06
Lubricant	liter	4.4E+05	3.3E+05	to	5.9E+05	4.1E+05	3.0E+05	to	5.5E+05	4.3E+05	3.1E+05	to	5.7E+05
Waste management, tarps	kg	N/A	N/A	to	N/A	8.2E+04	8.2E+04	to	3.9E+05	N/A	N/A	to	N/A

Note: Tkm = thousand kilometers

Table 29. Switchgrass Production: Farm Equipment and Storage Facilities

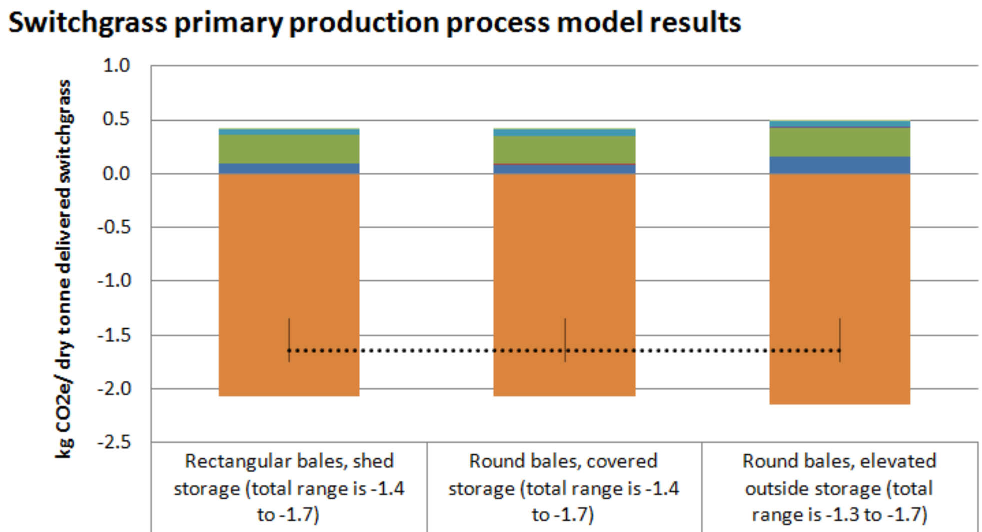
Input	Units*	Rectangular bales, shed storage				Round bales, tarp covered				Round bales, net wrapped elevated			
		Best Estimate	Range (best to worst case)			Best Estimate	Range (best to worst case)			Best Estimate	Range (best to worst case)		
Baler, midsize-large rectangular	pieces	4.7E+01	4.5E+01	to	5.0E+01	N/A	N/A	to	N/A	N/A	N/A	to	N/A
Baler, large round baler	pieces	N/A	N/A	to	N/A	5.7E+01	5.5E+01	to	6.1E+01	5.9E+01	5.7E+01	to	6.3E+01
Bale mover, rectangular	pieces	1.4E+01	1.3E+01	to	1.5E+01	N/A	N/A	to	N/A	N/A	N/A	to	N/A
Bale mover, round	pieces	N/A	N/A	to	N/A	2.2E+01	2.1E+01	to	2.3E+01	2.3E+01	2.2E+01	to	2.4E+01
Cultipack	pieces	6.8E-01	3.9E-01	to	1.6E+00	6.8E-01	3.9E-01	to	1.5E+00	7.1E-01	4.1E-01	to	1.6E+00
Disk	pieces	3.4E+00	1.9E+00	to	7.7E+00	3.3E+00	1.9E+00	to	7.6E+00	3.5E+00	2.0E+00	to	7.9E+00
Drill	pieces	2.7E+00	1.7E+00	to	6.0E+00	2.7E+00	1.7E+00	to	6.0E+00	2.8E+00	1.8E+00	to	6.2E+00
Fert & herb application	pieces	8.0E+01	7.4E+01	to	9.4E+01	8.0E+01	7.4E+01	to	9.3E+01	8.3E+01	7.7E+01	to	9.6E+01
Harrow	pieces	2.7E+00	1.3E+00	to	5.7E+00	2.7E+00	1.3E+00	to	5.6E+00	2.8E+00	1.4E+00	to	5.8E+00
Mower	pieces	3.4E-01	1.9E-01	to	7.8E-01	3.4E-01	2.0E-01	to	7.7E-01	3.5E-01	2.0E-01	to	8.0E-01
Mower-conditioner (2.7–4.3m wide)	pieces	N/A	N/A	to	N/A	6.0E+01	5.8E+01	to	6.4E+01	6.3E+01	6.0E+01	to	6.6E+01
Mower-conditioner (4.3 – 4.9m wide) or self propelled swather	pieces	6.5E+01	6.1E+01	to	6.9E+01	N/A	N/A	to	N/A	N/A	N/A	to	N/A
No-till drill	pieces	3.6E+00	2.0E+00	to	8.2E+00	3.6E+00	2.1E+00	to	8.1E+00	3.7E+00	2.1E+00	to	8.4E+00
Plow-disk	pieces	4.1E-01	2.4E-01	to	6.4E-01	4.1E-01	2.5E-01	to	6.3E-01	4.3E-01	2.5E-01	to	6.5E-01
Rake	pieces	2.4E+01	2.3E+01	to	2.6E+01	2.4E+01	2.3E+01	to	2.5E+01	2.5E+01	2.4E+01	to	2.6E+01
Bale/module storage pad &/or building constructed area	hectare	3.5E+00	2.5E+00	to	5.6E+00	1.3E+01	9.4E+00	to	2.0E+01	6.7E+00	2.9E+01	to	6.4E+01

* The unit "pieces" refers to the number of pieces of equipment needed.

Table 30. Switchgrass Production: Emissions at Farm Storage Facilities

Output	Units	Rectangular bales, shed storage				Round bales, tarp covered				Round bales, net wrapped elevated			
		Best Estimate	Range (best to worst case)			Best Estimate	Range (best to worst case)			Best Estimate	Range (best to worst case)		
Carbon dioxide (CO_2): biogenic, from the air	kg	-2.9E+09	-2.8E+09	to	-3.1E+09	-2.9E+09	-2.8E+09	to	-3.1E+09	-3.0E+09	-2.9E+09	to	-3.2E+09
Carbon dioxide (CO_2): non-biogenic, to air	kg	1.2E+07	8.5E+06	to	1.6E+07	1.1E+07	8.0E+06	to	1.4E+07	1.1E+07	8.3E+06	to	1.5E+07
Carbon dioxide (CO_2): biogenic, to air	kg	4.9E+08	3.5E+08	to	7.0E+08	4.9E+08	3.7E+08	to	6.6E+08	6.0E+08	4.8E+08	to	7.7E+08
Methane (CH_4): non-biogenic, to air	kg	9.5E+01	7.0E+01	to	1.3E+02	8.8E+01	6.5E+01	to	1.2E+02	9.2E+01	6.7E+01	to	1.2E+02
Nitrous oxide (N_2O): non-biogenic, to air	kg	1.4E+02	1.0E+02	to	1.9E+02	1.3E+02	9.5E+01	to	1.7E+02	1.3E+02	9.8E+01	to	1.8E+02

Using the IPCC 2007 GWPs and considering only emissions of CO_2, CH_4, and N_2O, Figure 14 shows very little difference in the results by bale type. On the basis of primary production process emissions, a net GHG savings of between 1.4 and 1.7 tonnes CO_2e/ dry tonne of switchgrass for the rectangular and tarp-covered round bales and 1.3 and 1.7 tonnes CO_2e/ dry tonne of switchgrass for the net-wrapped round bales.



	Rectangular bales, shed storage (total range is -1.4 to -1.7)	Round bales, covered storage (total range is -1.4 to -1.7)	Round bales, elevated outside storage (total range is -1.3 to -1.7)
Establishment: lime application	0.012	0.012	0.012
Establishment: fuel combustion	0.00028	0.00028	0.00029
Reseeding: fuel combustion	0.00066	0.00066	0.00068
Maintenance: as uptake	-2.1	-2.1	-2.1
Maintenance: fertilizer application	0.056	0.056	0.058
Maintenance: fuel combustion	0.0017	0.0017	0.0018
Harvest: losses	0.26	0.26	0.27
Harvest: fuel combustion	0.0057	0.0051	0.0053
Storage: losses	0.090	0.086	0.15
Primary production total	-1.6	-1.6	-1.6

Figure 14. Switchgrass, GHG Emissions for Primary Production Processes

4.2.2 Data Quality Assessment

The results of unit process data quality evaluation for Stage #1b are provided in Table 31. Data quality indicators and life cycle significance determinations are listed for unit processes included in the model of this stage.

Analysis of the life cycle significance of processes shows that the composite construction process for switchgrass acquisition is below 0.1 percent of life cycle emissions. The operation process, though a negative result, is well above the cutoff criteria at -19.6 percent.

Table 31. Switchgrass Acquisition (LC Stage #1b) Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Life Cycle Significance of Process
1	Acquisition of Switchgrass, Operation	3,2,1,1,1	-19.6%
1	Acquisition of Switchgrass, Construction	3,2,1,1,1	0.06%

4.2.3 Results

This section presents the life cycle GHG emissions for Stage #1b. The first part of this section presents the deterministic results for three different methods of baling and storing the harvested switchgrass. The base case involves processing the harvested switchgrass as rectangular bales and storing these bales under cover. Two alternative cases were also investigated, one where the switchgrass is also processed as round bales but is stored uncovered. In the deterministic analysis, each uncertain variable was set to its most likely value based on engineering judgment.

The model for this LC stage was implemented in Excel in such a manner that systematic uncertainty analysis and sensitivity analysis of critical variables that influence outputs (such as the amount of biomass lost during harvesting and storage or the rate of CO_2 emissions from lime) could not be performed. However, a number of the input flows in the model for this stage are uncertain, and a separate analysis established minimum and maximum values for input flows and direct GHG emissions. Varying the input flows alters GHG emissions as a result of changes in secondary emissions. Similarly, allowing the direct emission of GHGs to vary directly influences the resulting CO_2e emissions. The second part of this section presents the range in GHG emissions when input flows and direct emissions are allowed to be varied in a probabilistic simulation. The third part of this section presents a sensitivity analysis for the GHG emissions from these uncertain variables.

Given the data quality score of 3 in the "Source Reliability" category and according to the Framework and Guidance Document, the unit process data are categorized as of low quality and have been varied to the minimum and maximum values estimated as described above. Based on the minimum and maximum values for consumables, farm equipment and storage facilities production, and emissions at the farm, emission of N_2O from nitrogen fertilizer use is potentially a significant contributor to overall GHG emissions for this stage. However, these emissions are included in the direct land use evaluation (LC Stage #1c) rather than in this stage.

4.2.3.1 Deterministic Greenhouse Gas Emissions

The deterministic results for Stage #1b are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S1b.Summ, which presents the input flows, output flows (products and co-products) and GHG emissions for this stage. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the functional unit. The operations unit process references are in sheet S1a.UP.O.FarmOp and the construction unit process references are in sheet S1a.UP.C.FarmCon. GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are also presented in this sheet.

Table 32 presents the life cycle GHG emissions for Stage #1b for the baseline case (rectangular bales, covered) in terms of the reference flow for this stage, which is 1 tonne of switchgrass ready for transport. This table presents the total emissions of 1) non-biogenic carbon dioxide

from operation and construction, 2) biogenic carbon dioxide from operation and construction, 3) methane from operation and construction, 4) nitrous oxide from operation and construction, and 5) other GHGs from operation and construction. This last category, other GHGs, captures emissions from GHGs other than carbon dioxide, methane, or nitrous oxide, or emissions that are expressed in carbon dioxide equivalents and cannot be differentiated into the primary GHGs. The second column in the table presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the IPCC 2007, IPCC 2001, and IPCC 1996 estimates, respectively.

As indicated in Table 32, the switchgrass biomass extracts far more CO_2 from the air than the rest of the operation emits in GHGs. Excluding the CO_2 extracted from the air by the switchgrass biomass, there are about 66,000 g CO_2e emitted per tonne of switchgrass (dry) during operations and about 4,800 g CO_{2e} emitted per tonne of switchgrass from construction activities (using any of the IPCC global warming potentials). Construction emissions are about 7 percent of total emissions when the CO_2 extracted from the air by the switchgrass biomass is ignored.

Table 32. LC Stage #1b GHG Emissions for Baseline Case: Rectangular Bales, Covered (per Dry Tonne of Switchgrass Ready for Transport)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/tonne Switchgrass)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne Switchgrass) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne Switchgrass) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne Switchgrass) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	66,000	66,000	66,000	66,000
Non-biogenic CO_2 – Construction	4,800	4,800	4,800	4,800
Non-biogenic CO_2 – Subtotal	71,000	71,000	71,000	71,000
Biogenic CO_2 – Operation	-1,700,000	-1,700,000	-1,700,000	-1,700,000
Biogenic CO_2 – Construction	0	0	0	0
Biogenic CO_2 – Subtotal	-1,700,000	-1,700,000	-1,700,000	-1,700,000
CH_4 – Operation	110	2,900	2,600	2,400
CH_4 – Construction	13	330	300	270
CH_4 – Subtotal	130	3,200	2,900	2,700
N_2O – Operation	63	19,000	19,000	19,000
N_2O – Construction	0	60	60	63
N_2O – Subtotal	63	19,000	19,000	20,000
Other GHG – Operation		0	0	0
Other GHG – Construction		0	0	0
Other GHG – Subtotal		0	0	0
Operation – Total		-1,600,000	-1,600,000	-1,600,000
Construction– Total		5,200	5,200	5,100
Grand Total		-1,600,000	-1,600,000	-1,600,000

Note: Subtotals and totals may not sum exactly due to rounding.

Table 33 presents the life cycle GHG emissions for the second case involving round bales that are covered during storage. Table 34 presents the life cycle GHG emissions for the third case involving round bales that are left uncovered during storage. The total emission of GHGs in carbon dioxide equivalent concentrations is the same for these two cases as for the base case.

Excluding the CO_2 extracted from the air by the switchgrass biomass (which is the same in all three cases), there are differences in operation-related and construction-related emissions between the cases, but the differences are slight (approximately 1 or 2 percent of the total GHG emissions after excluding the CO_2 extracted from the air by the switchgrass biomass).

Table 33. LC Stage #1b GHG Emissions for Second Case: Round Bales, Covered (per Dry Tonne Switchgrass Ready for Transport)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/tonne Switchgrass)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne Switchgrass) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne Switchgrass) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne Switchgrass) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	65,000	65,000	65,000	65,000
Non-biogenic CO_2 – Construction	6,900	6,900	6,900	6,900
Non-biogenic CO_2 – Subtotal	72,000	72,000	72,000	72,000
Biogenic CO_2 – Operation	-1,700,000	-1,700,000	-1,700,000	-1,700,000
Biogenic CO_2 – Construction	0	0	0	0
Biogenic CO_2 – Subtotal	-1,700,000	-1,700,000	-1,700,000	-1,700,000
CH_4 – Operation	110	2,900	2,600	2,400
CH_4 – Construction	19	470	440	400
CH_4 – Subtotal	130	3,300	3,100	2,800
N_2O – Operation	63	19,000	19,000	19,000
N_2O – Construction	0	110	110	110
N_2O – Subtotal	63	19,000	19,000	20,000
Other GHG – Operation		0	0	0
Other GHG – Construction		0	0	0
Other GHG – Subtotal		0	0	0
Operation – Total		-1,600,000	-1,600,000	-1,600,000
Construction– Total		7,500	7,500	7,400
Grand Total		-1,600,000	-1,600,000	-1,600,000

Note: Subtotals and totals may not sum exactly due to rounding.

Table 34. LC Stage #1b GHG Emissions for Third Case: Round Bales, Uncovered (per Dry Tonne Switchgrass Ready for Transport)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/tonne Switchgrass)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne Switchgrass) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne Switchgrass) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne Switchgrass) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	67,000	67,000	67,000	67,000
Non-biogenic CO_2 – Construction	4,300	4,300	4,300	4,300
Non-biogenic CO_2 – Subtotal	71,000	71,000	71,000	71,000
Biogenic CO_2 – Operation	-1,700,000	-1,700,000	-1,700,000	-1,700,000
Biogenic CO_2 – Construction	0	0	0	0
Biogenic CO_2 – Subtotal	-1,700,000	-1,700,000	-1,700,000	-1,700,000
CH_4 – Operation	120	2,900	2,700	2,500
CH_4 – Construction	12	290	270	250
CH_4 – Subtotal	130	3,200	3,000	2,700
N_2O – Operation	65	19,000	19,000	20,000
N_2O – Construction	0	65	64	67
N_2O – Subtotal	65	19,000	19,000	20,000
Other GHG – Operation		0	0	0
Other GHG – Construction		0	0	0
Other GHG – Subtotal		0	0	0
Operation – Total		-1,600,000	-1,600,000	-1,600,000
Construction– Total		4,700	4,600	4,600
Grand Total		-1,600,000	-1,600,000	-1,600,000

Note: Subtotals and totals may not sum exactly due to rounding.

4.2.3.2 Probabilistic Uncertainty Analysis

Due to the nature of the LC Stage #1b segment of the F-T Jet Fuel Spreadsheet Model, the probabilistic uncertainty analysis contained in this section is different from that reported for other LC Stages. Within the switchgrass production portion of the model, minimum, maximum, and best estimate values are calculated or otherwise provided for all of the input/output flows, and for direct emissions. However, this segment of the F-T Jet Fuel Spreadsheet Model was assembled as an independent model and then embedded in the F-T Jet Fuel Spreadsheet Model. Therefore, the switchgrass model is best represented as an independent data source that provides a GHG result with a bounded minimum and maximum range, as well as a best estimate. Secondary life cycle profiles are linked within the F-T Jet Fuel Spreadsheet Model to the switchgrass model. Therefore, varying switchgrass parameters results in changes to secondary emissions, and does not affect emissions from primary processes. Therefore, a full probabilistic uncertainty analysis could not be completed. Instead, an abbreviated analysis was completed, which includes uncertainty analysis for CO_2, CH_4, and N_2O, which could be parameterized across a portion of LC Stage #1b of the F-T Jet Fuel Spreadsheet Model.

A separate analysis provided ranges for input flows and associated emissions of non-biogenic CO_2, CH_4, and N_2O. The input flows that had the most influence on total non-biogenic CO_2e emissions for this stage are presented in Table 35, which presents the minimum and maximum values for these input flows as well as the minimum and maximum values for the direct emissions of non-biogenic CO_2, CH_4, and N_2O. The separate analysis generated the best

estimates for input flows and GHG emissions by choosing "best estimates" for parameters in the underlying switchgrass life cycle inventory model. Similarly, the minimum estimates for input flows and GHG emissions were generated by selecting minimum or maximum values for the parameters in the underlying switchgrass life cycle inventory model, such that minimum GHG emissions are generated. The maximum estimates for input flows and GHG emissions were generated by selecting minimum or maximum values for the parameters in the underlying switchgrass life cycle inventory model, such that maximum GHG emissions are generated.

All the input flows shown in Table 35 are at their maximum when GHG emissions are at their maximum and, conversely, are at their minimum when GHG emissions are at their minimum. Because the minimum and maximum values only occur when parameters in the underlying switchgrass life cycle inventory model are chosen to minimize or maximize GHG emissions, the likelihood that all the parameters would take on these values simultaneously is low. Therefore, the minimum and maximum values are less likely to occur than the best estimate. Triangular distributions are useful for describing data when only limited data are available, when minimum and maximum values are known, along with an informed estimate (best estimate). Therefore, because minimum, maximum, and informed estimate values are available for the parameters presented below, and because the minimum and maximum values are considered less likely to occur than the best estimate, all variables in Table 35 are assumed to follow a triangular distribution.

To quantify the influence on the calculated GHG emissions of uncertainty in the variables presented in Table 35, probabilistic simulations were performed. The biogenic emissions of CO_2 for this stage are negative, indicating the switchgrass extracts CO_2 from the atmosphere. The absolute values of these emissions are much higher than all other CO_2e emissions, which makes it difficult to see the influence of varying input flows or direct emissions of GHGs on the total CO_2e emissions for this stage. Consequently, the output variable examined in the probabilistic simulations is the total CO_2e emissions of non-biogenic CO_2, CH_4, and N_2O.

In this evaluation, probabilistic simulations were performed for total non-biogenic life cycle GHG emissions using the IPCC 2007 global warming potentials. CO_2 equivalent emissions were calculated relative to the stage reference flow of 1 dry tonne of switchgrass ready for transport. Table 36 presents the statistics for the CO_2e emissions developed from the simulations. Figure 15 presents the cumulative distribution and probability density function for CO_2 equivalent emissions relative to the LC Stage #1b reference flow. In Figure 15, the vertical scale on the left is for the probability density function and the vertical scale on the right is for the cumulative distribution.

Table 35. Uncertainty in Key Input Flows and Direct Emissions for Switchgrass Acquisition (LC Stage #1b)

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters and Direct Emissions-Switchgrass Farming, Operation							
Carbon dioxide (CO_2): non-biogenic, to air	kg/tonne	21.0	17.3	25.2	21.0	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Methane (CH_4): to air	kg/tonne	6.73E-05	4.96E-05	8.94E-05	6.73E-05	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Nitrous oxide (N_2O): total to air	kg/tonne	9.83E-05	7.24E-05	1.31E-04	9.83E-05	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Lime, at farm	kg/tonne	25.7	24.6	27.3	25.7	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Fertilizer as nitrogen, at farm	kg/tonne	12.9	12.3	13.7	12.9	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Fertilizer as phosphorous, at farm	kg/tonne	0.85	0.84	0.87	0.85	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Diesel fuel, at farm	kg/tonne	2.7	2.0	3.5	2.7	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Input Parameters-Switchgrass Farming, Construction							
Baler, midsize-large rectangular	pcs/tonne	3.32E-05	3.18E-05	3.53E-05	3.32E-05	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Mower-conditioner (14-16 ft) or self-propelled swather (16 ft)	pcs/tonne	4.58E-05	4.38E-05	4.87E-05	4.58E-05	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Bale/module storage pad &/or building constructed area	ha/tonne	2.45E-06	1.69E-06	3.93E-06	2.45E-06	Triangular	Minimum, maximum, and best estimate determined in separate analysis.

The total non-biogenic CO_2 equivalent emissions relative to the reference flow range from 89 to 100 kg CO_2e/tonne switchgrass, with a median value of 94 kg CO_2e/tonne switchgrass, a mean of 94 kg CO_2e/tonne switchgrass and a standard deviation of 2 kg CO_2e/tonne switchgrass. Eighty percent of the distribution lies between 91 and 96 kg CO_2e/tonne switchgrass, and the middle fifty percent of the distribution lies between 92 and 95 kg CO_2e/tonne switchgrass.

Table 36. LC Stage #1b: Probabilistic Uncertainty Analysis; Statistics for Non-Biogenic CO_2e Emissions

Statistical Parameter	Mass of GHG Emitted to Atmosphere (kg CO_2e/tonne switchgrass) (IPCC 2007 GWP)
Minimum	89
10%	91
25%	92
Median (50%)	94
75%	95
90%	96
Maximum	100
Mean	94
Mode	94
Stand. Deviation	2

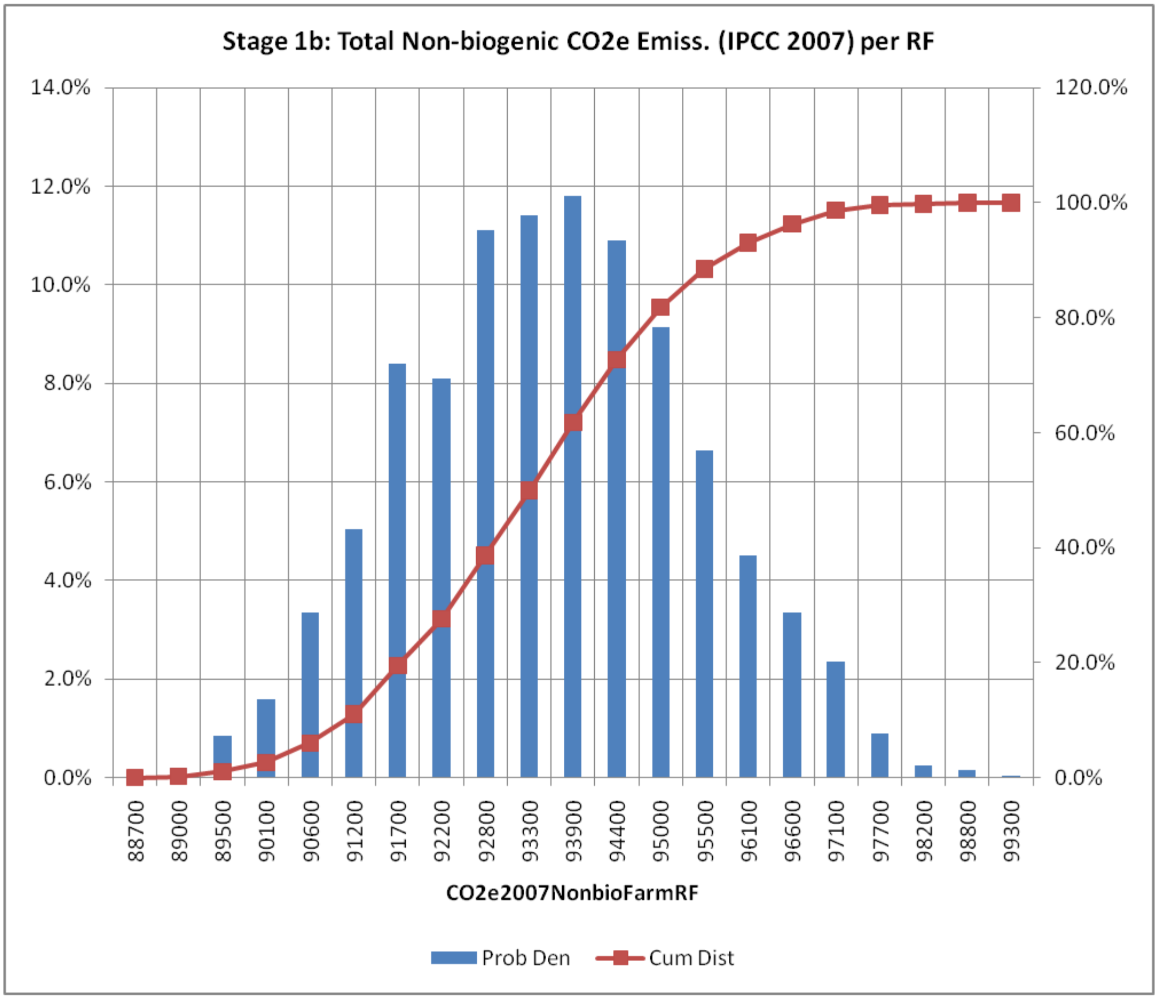


Figure 15. LC Stage #1b Probability Density Function and Cumulative Distribution of CO_2e Emissions (using IPCC 2007 GWP) (per tonne Switchgrass Ready for Transport)

4.2.3.3 Sensitivity Analysis

In the sensitivity analysis, the total non-biogenic CO_2e emission using the IPCC 2007 global warming potentials was calculated for each key variable in Table 35. Table 37 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions, based on the minimum and maximum values for consumables, farm equipment, storage facilities production, and emissions at the farm. The absolute difference for each key variable is also shown, and key variables are listed from highest to lowest based on their absolute difference. This same result is presented graphically in the tornado chart presented in Figure 16.

The variable that has the most influence is Carbon Dioxide, Direct Emissions from Farm Activities ("CO2N_x" in Figure 16). The next four most important variables, nitrogen fertilizer, bale storage pad, diesel fuel and lime, are important for their secondary emissions of GHGs (i.e., the emissions of GHGs in their production and transport to the farm). All other key variables have a negligible influence on total non-biogenic CO_2e emissions. Recall that emission of N_2O

from nitrogen fertilizer use is potentially a significant contributor to overall non-biogenic GHG emissions for this stage. However, these emissions are included in the direct land use evaluation (Stage #1c), rather than in this stage.

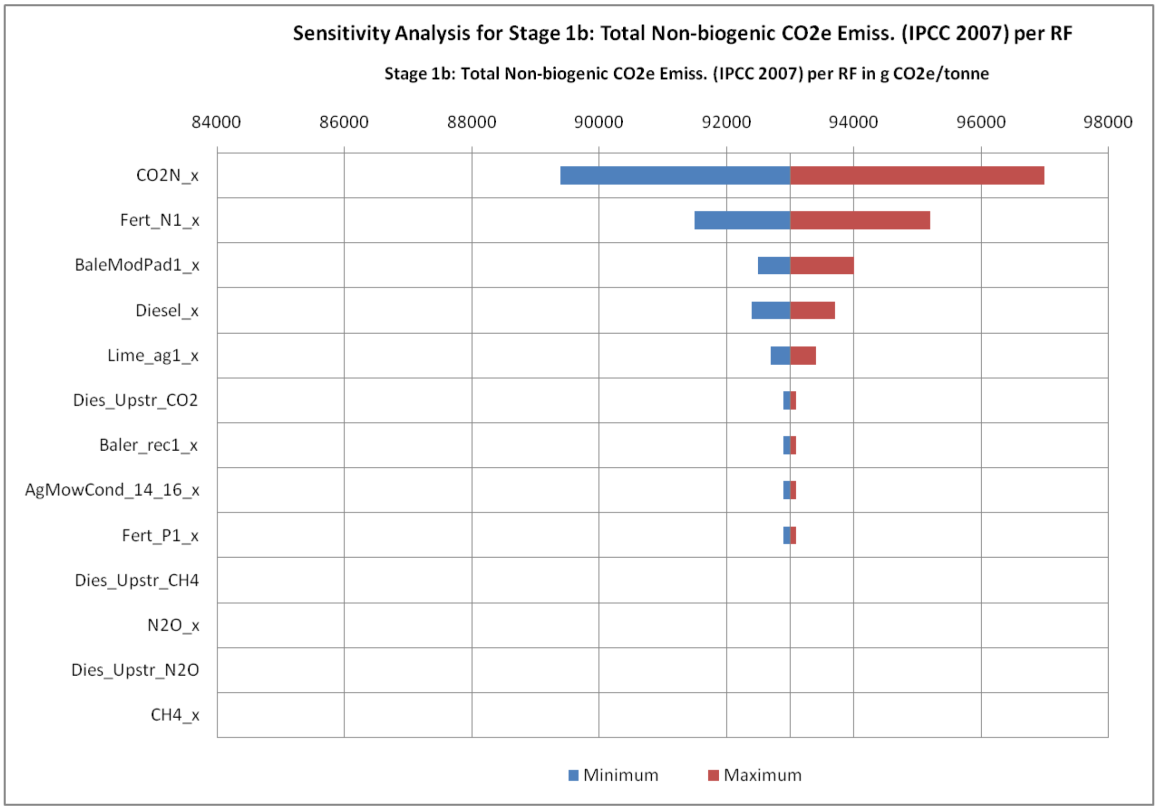


Figure 16. LC Stage #1b Sensitivity Analysis Results for Total Non-biogenic CO_2e Emissions (Using IPCC 2007 GWP) (g CO_2e per dry tonne Switchgrass Ready for Transport)

Table 37. Sensitivity Analysis Results for Non-Biogenic CO_2e Emissions for Stage #1b (Using IPCC 2007 GWP) (g CO_2e/Dry Tonne Switchgrass Ready for Transport)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/tonne switchgrass)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x	kg/tonne	21	17.3	25	89400	97000	7650
Fertilizer as nitrogen, at farm	Fert_N1_x	kg/tonne	12.9	12.3	13.7	91500	95200	3700
Bale/module storage pad &/or building constructed area	BaleModPad1_x	ha/tonne	0.00000245	0.00000169	0.00000393	92500	94000	1480
Diesel fuel, at farm	Diesel_x	kg/tonne	2.67	1.97	3.55	92400	93700	1300
Lime, at farm	Lime_ag1_x	kg/tonne	25.7	24.6	27.3	92700	93400	703
Upstream CO_2 emitted per kg petroleum diesel fuel produced	Dies_Upstr_CO2	kg CO_2/kg	0.718	0.683	0.754	92900	93100	192
Baler, midsize-large rectangular	Baler_rec1_x	pcs/tonne	0.0000332	0.0000318	0.0000353	92900	93100	168
Mower-cond. (14-16 ft) or SP swather (16 ft)	AgMowCond_14_16_x	pcs/tonne	0.0000458	0.0000438	0.0000487	92900	93100	153
Fertilizer as phosphorous, at farm	Fert_P1_x	kg/tonne	0.854	0.838	0.873	92900	93100	121
Upstream CH_4 emitted per kg petroleum diesel fuel produced	Dies_Upstr_CH4	kg CH_4/kg	0.004	0.0038	0.0042	93000	93000	26.7
Nitrous oxide (N_2O): Direct emissions from farm activities	N2O_x	kg/tonne	0.0000983	0.0000724	0.000131	93000	93000	17.3
Upstream N_2O emitted per kg petroleum diesel fuel produced	Dies_Upstr_N2O	kg N_2O/kg	0.000013	0.0000123	0.0000136	93000	93000	1.03
Methane (CH_4): Direct emissions from farm activities	CH4_x	kg/tonne	0.0000673	0.0000496	0.0000894	93000	93000	0.995
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x	kg/tonne	21	17.3	25	89400	97000	7650

4.3 Land Use (LC Stage #1c)

This section addresses the direct and indirect land use issues associated with switchgrass production, as summarized in **Section 3.2.5**. The land use analysis completed for this study covers four areas, two related to direct land use changes and two related to indirect land use changes. Direct land use changes refer to changes in GHG emissions that occur when land that was previously used for crops, pasture, forest, or some other use is changed to switchgrass production. One GHG emission change involves the difference in N_2O emissions from nitrogen fertilizers when land changes from its previous use to switchgrass production. The change in N_2O emissions results from changes in farming practices (i.e., the amount of nitrogen fertilizers used) when land use changes. A second change involves changes in carbon stocks when land changes to switchgrass production. Carbon stocks considered in this analysis are aboveground biomass, belowground biomass, and soil organic matter.

Indirect land use changes refer to changes in GHG emissions that occur when land uses that occurred before switchgrass production are shifted to other lands after switchgrass production begins. For example, if switchgrass production displaces land used to grow corn, then land that was formerly forest may be converted to corn production to offset some or all of the corn production displaced by switchgrass. For indirect land use, one GHG emission change involves the difference in N_2O emissions from nitrogen fertilizers when land changes from a previous use (such as forest) to a new use (such as corn production). A second GHG emission change involves changes in carbon stocks when land changes from a previous use (such as forests) to a new use (such as corn production). For both direct and indirect land use, the net difference in N_2O emissions and carbon stocks are of interest. In addition to N_2O emissions, there are other GHG emissions that can change as a result of changed farming practices when land use changes, but changes in N_2O emissions are believed to be the most significant. For a comparison of modeled land use results with those published by US EPA's RFS2 analysis (US EPA, 2010a), please refer to subsection **4.3.3 Results**.

4.3.1 Modeling Approach and Data Sources

The following text provides an overview of the modeling approach, data sources, major assumptions, and equations that were incorporated into the model for LC Stage #1c, Land Use. As described in US EPA (2010), research indicates that indirect land use change is not the only significant indirect impact related to expansion of commercial switchgrass production. For example, if feed crops are displaced, there are likely to be indirect impacts in the livestock sector (e.g., the total amount of beef production may be affected) that can result in life cycle GHG emissions. Due to time and resource constraints, indirect land use change was the only indirect impact considered in this case study report.

4.3.1.1 Land Used for Each LC Stage

Most of the LC stages considered in this study would require some amount of land area to be converted from its existing state to a new use. For LC Stage #1b, all land use change occurs as a result of changes in cropland and cropping patterns. For most other LC Stages, land use change would occur as a result of installation of various other facilities, such as pipelines, a CBTL plant, or enhanced oil recovery fields. The total area of land that would be altered as a result of installation of facilities under each LC stage was calculated, based on estimated facility sizes. Table 38 presents a list of the facilities considered in this study that would result in land use change, and an estimate of the total land area used for each LC stage.

As shown, relatively little land is used in Stages 1a, 2a, 3a, 4, and 5. Stage 1b (biomass acquisition) uses a lot of land and changes the uses of a lot of land. LC Stage #3b (CO_2 pipeline) uses a fair amount of land for the pipeline, but a long pipeline is presumed to use existing rights-of-way for utility lines (either belowground pipes or aboveground power lines), and therefore, the actual land use change is likely to be minimal. LC Stage #3c (EOR) has a potentially large footprint, since the total land area is large where EOR work activities occur. However, within this large work area, the land that would be modified to install wells for injecting CO_2, injecting water, and pumping out petroleum products, and the land needed for processing the petroleum products is small compared to the total work area. Also, EOR is done on land that has already undergone primary and secondary oil recovery operations, which means that the wells have already been installed and much of the buildings and equipment for processing the extracted petroleum products is already in place. Hence, the land use change from secondary oil recovery operations to EOR is minimal. LC Stage #3d is saline aquifer sequestration, but sequestration is expected to have a small footprint, since it involves the installation and operation of wells to inject supercritical CO_2 into a saline aquifer. Thus, the LC stage that results in the most significant land use change is LC stage #1b. The changes in GHG emissions due to changing land from existing uses to switchgrass production (both direct and indirect land use changes) is the focus of the remainder of this section.

Table 38. Land Use for Each LC Stage

LC Stage	Land Use in Hectares (ha), per Study Period			
	0% Switchgrass	14% Switchgrass	16% Switchgrass	31% Switchgrass
LC Stage #1a (Coal Mine)	275	275	275	275
LC Stage #2a (Railroad Spur)	123	123	123	123
LC Stage #1b (Farm Crop Land)	0	60,900	68,500	145,000
LC Stage #1b (Farm Storage Land)	0	585	659	1,390
LC Stage #2b (Switchgrass Transport)	0	0	0	0
LC Stage #3a (CBTL)	16	16	16	16
LC Stage #3b (CO_2 Pipeline)	4,220	4,220	4,220	4,220
LC Stage #3c (EOR)	37,300	37,300	37,300	37,300
LC Stage #3d (Saline Aquifer Sequestration)	0	0	0	0
LC Stage #4 (F-T Jet Fuel Pipeline)	98	98	98	98
LC Stage #5 (F-T Jet Fuel Use)	0	0	0	0
Total Stage #1b	0	61,500	69,200	146,000
Part of Stage #3c (5% of Total Land)	1,860	1,860	1,860	1,860
Total Area Using All Stages	42,000	103,000	111,000	188,000
Total Area Using 5% of LC Stage #3c	6,600	68,100	75,800	153,000
LC Stage 1b as Percent of Total (all LC Stage #3c)	0.0%	59.5%	62.2%	77.7%
LC Stage #1b as Percent of Total (5% LC Stage #3c)	0.0%	90.3%	91.3%	95.7%

4.3.1.2 Direct Land Use Change: N_2O Emissions from Soil

All soils will emit some N_2O, but emissions are strongly correlated with the addition of organic and inorganic nitrogen fertilizers. The IPCC identifies three approaches to estimating N_2O emissions from managed soils. Tier 1 estimates are based on the nitrogen application rates alone. The IPCC default for direct emissions is that 1 percent (0.3-3 percent) of applied nitrogen is released as N_2O-N (IPCC, 2006, Ch. 11, Table 11.2, page 11-11). This corresponds to 1.57 g of N_2O (0.5 to 4.7 g of N_2O) for each 100 g of applied nitrogen.[10] IPCC also provides estimates of indirect N_2O emissions, which corresponds to N_2O released from nitrogen after it has run off or volatilized from the point of application. This is estimated to be an additional 0.3 percent (0.11 percent -3 percent) of nitrogen fertilizer applied, corresponding to 0.5 g of N_2O (0.2 to 5 g of N_2O) for each 100 g of applied nitrogen. The GREET model (ANL, 2009) uses a Tier 1 approach to calculate the N_2O emissions from production of switchgrass, with about 1.3 g N_2O emitted per 100 g applied nitrogen; the lower value results from taking into account that measured N_2O emissions include both background and fertilizer-induced emissions.

Tier 3 estimates use models to determine N_2O emissions. In its inventory of GHG emissions and sinks, the US EPA uses the DAYCENT model (US EPA, 2009d). In addition to N inputs, DAYCENT accounts for other factors including water, temperature, oxygen levels, labile soil carbon availability, and plant nitrogen demand. On average, the US EPA reports that the DAYCENT model estimates are consistent with measured values, and that the IPCC estimate of 1.57 g N_2O per 100 g N is roughly 60 percent too low (US EPA, 2009c, 2009d). This suggests that a more appropriate value is 2.5 g N_2O emissions per 100 grams of applied nitrogen. Estimates of N_2O emissions are summarized in Table 39. Recognizing the significant uncertainty and variability of N_2O emissions, we estimate 2 g N_2O emissions (0.3 g – 5 g N_2O emissions) per 100 g of applied nitrogen fertilizer as N.

Table 39. Estimates of Nitrous Oxide (N_2O) Emissions

Data Source	g N_2O Emissions per 100 g Applied N in Fertilizer (Range as Applicable)
IPCC (IPCC, 2006)	1.57 (0.47-4.7)
GREET (ANL, 2009)	1.3
DAYCENT (US EPA, 2009c, 2009d)	2.5
This Study	2.0 (0.3-5.0)

[10] N_2O emissions are sometimes expressed in terms of N_2O-N (nitrogen in the form of N_2O). Conversion of N_2O–N emissions to N_2O emissions is calculated as follows: $N_2O = N_2O–N \times 44/28$.

The nitrous oxide emissions from growing switchgrass per tonne of switchgrass ready to be transported to the CBTL can be expressed as

Equation 1 $N_2O_{sw} = r_{N2O} \bullet N_{sw} / Y_{net\_sw}$

where N_2O_{sw} is in units of kg N_2O/tonne switchgrass, r_{N2O} is the N_2O emission factor (kg N_2O/kg-N), N_{sw} is the amount of nitrogen fertilizer used to grow switchgrass (kg-N/ha/yr), and Y_{net_w} is the switchgrass net yield. As discussed above, 2 g N_2O emissions per 100 g of applied nitrogen fertilizer was used as a best estimate for the variable r_{N2O}. As discussed in **Section 7**, N_{sw}, the nitrogen fertilizer application rate is 112 kg-N/ha/yr. The net switchgrass yield, Y_{net_sw}, varies between 8.4 and 8.7 tonnes/ha/yr based on the scenario assumed for baling and storing the switchgrass. The variable N_2O_{sw} is the annual emissions of N_2O from using nitrogen fertilizer divided by the annual net yield of switchgrass ready for transport.

The previous land use also had associated nitrous oxide emissions. For land that was previously pasture land, the amount of nitrogen fertilizer used is assumed to have been negligible. For land that was previously crop land, nitrogen fertilizer would have been used on most crops and so there would have been N_2O emissions associated with the use of this fertilizer. The amount of nitrogen fertilizer used on the crops depends on the actual crops grown. A variant of **Equation 1** can be used to estimate the nitrous oxide emissions that would have resulted from the crops displaced by the switchgrass:

Equation 2 $N_2O_{cr} = r_{N2O} \bullet N_{cr} \bullet s_{cr} / Y_{net\_sw}$

Two new variables, N_{cr} and s_{cr}, are introduced in **Equation 2**. As discussed in the Indirect Land Use Change subsection below, the amount of fertilizer that would have been used on the displaced crop (N_{cr}) is estimated to be 50 kg-N/ha/yr. The fraction of land used to grow switchgrass that was previously used to grow crops is s_{cr}. This variable is discussed in more detail in the Direct Land Use Change: Net CO_2 Emissions subsection, below. The net emission of N_2O (N_2O_{dir}) is the emission of N_2O from switchgrass (N_2O_{sw}) minus the emission of N_2O from the displaced crop (N_2O_{cr}).

There can also be emissions of N_2O from the use of nitrogen fertilizer on land apart from the land used to grow switchgrass. These emissions of N_2O result from changes in cropping patterns due to the introduction of switchgrass and associated displacement of other land uses. The increase or decrease in N_2O emissions resulting from changes in fertilizer use for displaced crops is addressed subsequently for indirect land use change.

4.3.1.3 Direct Land Use Change: Net CO_2 Emissions

The amount of carbon in the soil-plant system can be partitioned into various stocks or pools of carbon. Chapter 2, Table 2-1 of IPCC (2006) discusses a number of carbon stocks in the soil-plant system that can store carbon: aboveground biomass, belowground biomass, litter, dead wood, and soil organic matter (SOM). For this analysis, we define three carbon stocks: above ground biomass, below ground biomass (roots) and soil organic matter. Above ground biomass comprises all above-ground biomass material, including living and dead biomass. Below-ground biomass includes living and dead roots, prior to their degradation and incorporation into SOM. SOM consists of degraded biomass that has been incorporated into soil horizons. Some studies further divide SOM into fast turnover, slow turnover, and recalcitrant stocks. However, this investigation considers SOM as a single stock, with properties that represent these sub-stocks combined.

In the course of a year, the mass of carbon in these stocks change. During the growing season, the mass of carbon in aboveground and belowground biomass increases as the plant converts atmospheric CO_2 to biomass. At the end of the growing season, a portion of aboveground biomass is harvested and sent offsite. Most harvested biomass is used for food or energy production, and in a relatively short time (months), most of this biomass will be oxidized to CO_2. For this evaluation, all the switchgrass that is harvested and sent offsite is assumed to be oxidized within weeks or months. Similarly, the crops and pasture that the switchgrass has displaced are, for the most part, likely to be oxidized fairly quickly (within a year) after harvesting. The aboveground and belowground biomass that remains in the field will die eventually; for annual plants this will occur soon after harvest, for perennial plants, this will occur more gradually. For some perennial plants, such as trees, the amount of carbon stored in aboveground and belowground biomass can increase from year to year, up to a point. However, for any cropping system that is implemented on land for an extended period of time, the annual average mass of carbon in aboveground and belowground biomass stocks will approach a steady state value.

In summary, this study assumes that all of the biomass produced during one growing season will 1) be harvested and eventually oxidized, 2) remain in the aboveground or belowground biomass stock, or 3) die and enter the SOM stock. Most of the biomass that becomes part of the soil organic matter stock will also oxidize within months, but some of it can become incorporated into more recalcitrant SOM pools that degrade slowly, eventually sequestering a small fraction of the total carbon fixed by the original crops/vegetation. Alternatively, some crops and cropping systems (for instance, conventional farming practices that include frequent tilling) can facilitate the oxidation of SOM stocks that normally oxidize much slower. Thus, the mass of carbon in the SOM stock can increase or decrease with time, but, once again, only up to a point. For any cropping system that is consistently implemented on land over an extended period of time, the annual average mass of carbon in the SOM stock will approach a steady state value.

Over the course of the study period, changes in carbon in these three stocks will depend on the use of land before it was used for growing switchgrass. Switchgrass may be grown on land that was previously cropland, pastureland, forestland, or land in the Conservation Reserve Program. Eppink et al. (2010) estimate for the northern Missouri location of the CBTL considered in this case study that the land used for switchgrass would be 24 percent cropland and 76 percent hay pastureland. The cropland would have been previously used for sorghum, wheat, corn and soybeans. Also, approximately 81 percent of the land would be in Missouri and the remaining 19 percent in Iowa. Specifically, based on land use patterns at the northern Missouri location, Eppink et al. (2010) indicate that producing 1.55 million tons of switchgrass per year results in direct loss of production of 20,000 tons of soybeans, 17,000 tons of corn, 2000 tons of wheat, and 250 tons of sorghum. These direct changes will be partially balanced by indirect changes beyond the region directly surrounding the CBTL facility.

Additional information on direct land use change can be drawn from the US EPA analysis of potential switchgrass production to meet the RFS2 (US EPA, 2010a, 2010b). US EPA's analysis indicates that in a scenario in which 90 million tons of switchgrass are grown nationally, each hectare of switchgrass production in Missouri would be associated with a reduction of 0.32 hectares of hay pasture, 0.44 hectares of soybeans, 0.29 hectares of corn, and an *increase* of 0.14 hectares planted for wheat/grazing (used for grazing and wheat production), as well as smaller reductions in rice, cotton, silage and sorghum (US EPA, 2010a).

The specific direct land use changes will significantly affect the GHG emissions. If switchgrass is grown on land previously used for crops, there can be significant increases in soil carbon over time, but if switchgrass is grown on land previously use for hay pasture or other grasslands, the soil carbon build-up may be negligible. In addition, the extent to which indirect land use change is induced by the direct changes will depend on what crops or land uses are displaced, and how the market responds to the resulting reduced production of the previous crops.

The analysis below is developed with the previous land use as a variable. We define s_{cr} as the fraction of land that was previously in crops, and s_{pa} (i.e., 1- s_{cr}) as the fraction of land formerly used for pasture. For the baseline numerical calculation, we choose direct land use as 24 percent from cropland and 76 percent from pastureland, with these values ranging from 20 percent cropland and 80 percent pasture land to 40 percent cropland and 60 percent pasture land. We assume that no forest land will be directly converted to switchgrass production in this case study, and that any Conservation Reserve Program (CRP) land conversion will have GHG emissions similar to pastureland.

4.3.1.3.1 Carbon Stored in Aboveground Biomass

Aboveground biomass carbon storage has been calculated in the literature (Delucci, 2001; Andress, 2002; Curtright, 2010) by calculating the average standing carbon mass of the biomass feedstock. The net change in the mass of carbon (expressed as an equivalent mass of CO_2) stored in aboveground biomass can be expressed as:

Equation 3 $$CO_2e_{above} = -[(f_{b\_sw} \bullet T_{b\_ag} \bullet Y_{sw} \bullet C_{sw}) - (f_{b\_prev} \bullet T_{b\_ag} \bullet Y_{prev} \bullet C_{prev})] \bullet (CO_2/C) \bullet 1000 \text{ kg/tonne} / (Y_{net\_sw} \bullet T)$$

The variables Y_{sw} and Y_{prev} are the aboveground biomass for switchgrass and the previously grown plants (either crop or pasture) just before harvesting in tonne/ha/yr, C_{sw} and C_{prev} are the fractions of the switchgrass and previously grown biomass that are carbon in kg C/kg biomass, CO_2/C is the ratio of the molecular weight of CO_2 to the molecular weight of element carbon (44/12), and T is the study period or duration of the project, assumed to be 30 years. As discussed previously, Y_{net_w} is the switchgrass net yield or the amount of harvested aboveground biomass that is ready for transport to the CBTL facility. Because the amount of aboveground biomass fluctuates during the year (and over several years), a time period must be selected for estimating the average mass of above ground biomass in that time period. The variable T_{b_ag} is the time period over which the mass in the above ground biomass carbon stock is estimated, generally one year, and the variables f_{b_sw} and f_{b_prev} are the fractions of the maximum above ground biomass present, on average, over this time period.

The variable Y_{sw} is set to 10.455 tonnes/ha/yr to be consistent with calculations in LC Stages #1b and #3a. The net switchgrass yield, Y_{net_sw}, varies between 8.4 and 8.7 tonnes/ha/yr based on the scenario assumed for baling and storing the switchgrass. The variable Y_{prev} is estimated to be 1 tonne/ha/yr for crops (Y_{cr}) and 5 tonne/ha/yr for pasture (Y_{pa}). A value of 0.3992 has been used for C_{sw}, to be consistent with calculations in LC Stages #1b and #3a. A value of 0.4 has been used for C_{prev} for both crops (C_{cr}) and pasture (C_{pa}). The variable T_{b_ag} is assumed to be 1 year, and the variables f_{b_sw} and f_{b_prev} (f_{b_cr} for crops and f_{b_pa} for pasture) are both assumed to be 0.5. The variable $CO_{2eabove}$ ($CO_2e_{above\_cr}$ for crops and $CO_2e_{above\_pa}$ for pasture) has units of kg CO_2/dry tonne biomass ready for transport.

4.3.1.3.2 Carbon Stored in Belowground Biomass

For the belowground biomass carbon stock, Garten and Wullschlager (2000), as cited by Andress (2002) and Curtright (2010), report results using the ORNL Switchgrass model for increases in belowground (root) carbon content to a depth of 40 cm for conversion of land to switchgrass in five regions of the United States. They report an equilibrium value, C_{root_sw}, corresponding to 4.9 tonnes C per hectare of switchgrass for the north central zone of the United States, which includes Missouri. The root system of the displaced crop, C_{root_prev}, is taken to be 2 tonnes C per hectare for crops (C_{root_cr}). Curtright (2010) models switchgrass and pasture with similar below ground biomass; to distinguish these factors we assume here 4.8 tonnes C per hectare for pastureland (C_{root_pa}).

The net increase or decrease of carbon (expressed as an equivalent mass of CO_2) in the below ground biomass carbon stock in soil planted in switchgrass versus soil planted in its previous use is given by **Equation 4**.

Equation 4 $CO_2e_{below} = -(CO_2/C) \bullet 1000\ \text{kg/tonne} \bullet (C_{root\_sw} - C_{root\_prev}) / (Y_{net\_sw} \bullet T)$

The variable CO_2e_{below} ($CO_2e_{below\_cr}$ for crops and $CO_2e_{below\_pa}$ for pasture) has units of kg CO_2/dry tonne biomass ready for transport to the CBTL facility.

4.3.1.3.3 Carbon Stored in Soil Organic Matter

For the SOM stock, Garten and Wullschlager (2000), as cited by Andress (2002), report results using the ORNL Switchgrass model for five regions of the United States. For the north-central zone of the United States, which includes Missouri, the pre-harvest switchgrass yield is modeled to be 13.6 tonnes/ha/yr and soil carbon through the top 100 cm of the soil increases from 61 tonnes C/ha to 89 tonnes C/ha over 30 years of growing switchgrass, when the crops were previously grown on the land. The increase between the beginning and end of the 30-year simulation is 28 tonnes C/ha. Since the pre-harvest yield for this study is 10.455 tonnes/ha/yr, it was assumed that the increase in carbon content in the soil would be reduced proportionally to 21.5 tonnes C/ha. It was further assumed, following Curtright (2010), that there would be no increase or decrease in carbon in SOM when switchgrass is grown on soil that was previously used for pasture. If the net increase or decrease of carbon in SOM from growing switchgrass for 30 years is given by the variable ΔC_{soil_prev} , then this variable is 21.5 tonnes C/ha when switchgrass is grown in soil previously used for crops (ΔC_{soil_cr}) and 0 tonnes C/ha when switchgrass is grown in soil previously used for pasture (ΔC_{soil_pa}).

The net increase or decrease of carbon (expressed as an equivalent mass of CO_2) in the SOM carbon stock in soil planted in switchgrass versus soil planted in its previous crop is given by **Equation 5**.

Equation 5 $CO_2e_{soil} = -(CO_2/C) \bullet 1000\ \text{kg/tonne} \bullet \Delta C_{soil\_prev} / (Y_{net\_sw} \bullet T)$

The variable CO_2e_{soil} ($CO_2e_{soil\_cr}$ for crops and $CO_2e_{soil\_pa}$ for pasture) has units of kg CO_2e/dry tonne biomass ready for transport to the CBTL facility.

4.3.1.3.4 Total Direct CO_2 Emissions

Change in the total carbon stock due to land use change will be different for land that was previously cropland versus pastureland. Change in the total carbon stock due to direct land use change, per tonne of switchgrass delivered, can be expressed as the sum of the changes in carbon in the three carbon stocks in the soil-plant system: the aboveground biomass stock, the below-ground biomass stock, and the SOM stock. The change in the total carbon stock (expressed as an equivalent mass of CO_2) is given by **Equation 6**.

Equation 6 $$CO_2e_{stock} = s_{cr} \bullet (CO_{2above\_cr} + CO_2e_{below\_cr} + CO_2e_{soil\_cr}) + s_{pa} \bullet (CO_{2above\_pa} + CO_2e_{below\_pa} + CO_2e_{soil\_pa})$$

The variable CO_2e_{stock} is the total carbon stock with units of kg CO_2/dry tonne biomass ready for transport to the CBTL. The subscripts cr and pa are for crops and pasture, respectively.

Figure 17 illustrates how changes in the fraction of land previously used as cropland influences the calculated GHG emissions (measured as CO_2 equivalent emissions using the IPCC 2007 global warming potentials). The x-axis represents the fraction of land that was previously used for crops, as opposed to pasture. The y-axis represents the CO_2 equivalent emissions per tonne of switchgrass delivered. Negative values indicate that the mass of carbon in a pool is increasing (i.e., being pulled from the atmosphere and stored in the pool). As can be seen in the figure, land that was previously used for crops has more potential to sequester carbon in soil, so using this land for biomass production can result in significant carbon sequestration, up to a maximum, as shown in the figure, of roughly 400 kg CO_2e per tonne of switchgrass. Note, however, that this figure only includes impacts from direct land use changes. The impacts from indirect land use changes are discussed in the following section.

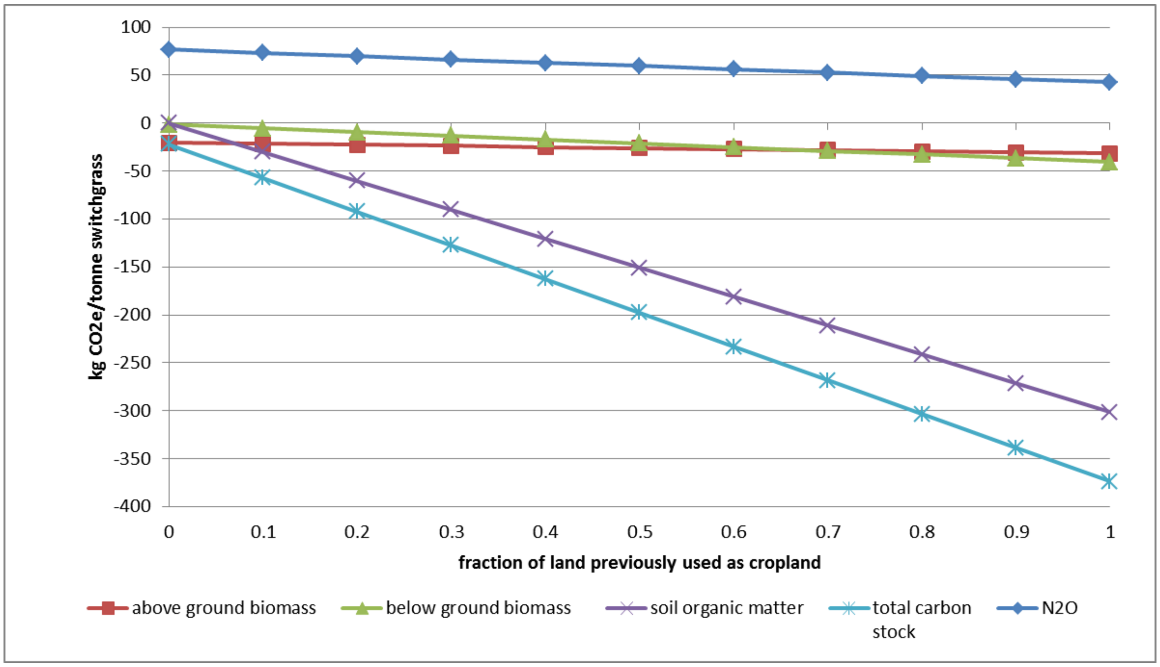


Figure 17. Influence of Previous Land Use on GHG Emissions from Direct Land Use Changes

4.3.1.4 Indirect Land Use Change Overview

The indirect land use change will depend not only on the switchgrass cultivated for a specific CBTL facility, but on the entire national and potentially global bioenergy and agricultural situation. These types of effects have been modeled by projecting future changes in the global agricultural markets and global land use, making use of global general equilibrium models of agricultural trade in combination with satellite data on trends in land use change (US EPA, 2010a, 2010b). Even these detailed models are limited by the challenge of predicting land use change decades into the future. Here we develop a simplified approach to approximating the indirect effects of land use change, and we draw on the results of the more detailed analyses for estimates of parameters and to benchmark the results. Specifically, we draw on the US EPA's estimates of indirect land use change resulting from growing switchgrass in the US for biofuels (US EPA, 2010a, 2010b).[11] The US EPA's estimates are based on a switchgrass yield in Missouri ranging from 17 wet tonnes/ha in 2002 increasing to 20 wet tonnes/ha in 2022. With late-summer harvests of switchgrass having a typical moisture content of about 40 percent (Blade Energy Crops, 2009), this corresponds to 10 to 12 dry tonnes/ha; comparable to the dry-weight yields assumed in this study.

When switchgrass or other biofuel feedstock is grown on agricultural land, the previous activities will be displaced. Although it is possible that the displaced activity will simply be displaced with no market response to the loss of the previous production, in the more general case it can be assumed that some fraction of the previous agricultural production will be replaced by increased production at some other location. Specifically, for each hectare of cropland converted directly to switchgrass, there will be some fraction of a hectare, s_{cr_ind} , that will be converted from pasture, grassland, forest or some other land use to cropland. Also, for each hectare of pasture land converted directly to switchgrass, there could be some fraction of a hectare, s_{pa_ind}, that will be converted from forest or some other non-pasture land use to pasture land.

For this analysis, we assume that the land indirectly converted to cropland from forest land, pasture land or other land will equal a fraction of the cropland directly displaced for switchgrass. We let f_{cr_ind} be the fraction of cropland directly displaced for switchgrass that becomes new cropland indirectly. In this case, s_{cr_ind} is given by the following expression.

Equation 7 $$s_{cr\_ind} = f_{cr\_ind} \bullet s_{cr}$$

For guidance on the potential range of values for s_{cr_ind}, we can draw on the US EPA RFS2 switchgrass analysis (US EPA, 2010a). The US EPA analysis indicates that for each hectare of land converted to switchgrass, there is, globally, approximately 0.3 hectares converted to cropland. This indicates that f_{cr_ind} is approximately 0.3. Drawing again from the US EPA analysis, about half the land use change is from pasture land and the other half is from "other land," which we assume is a mix of high and low carbon-stock lands, having an average carbon stock that is about half the typical values for temperate zone forests.

We assume that a fraction of the indirectly created crop land was formerly "other" land ($f_{cr\_ind\_oth}$, where $s_{cr\_ind\_oth} = f_{cr\_ind\_oth} \bullet s_{cr\_ind}$). We have set $f_{cr\_ind\text{-}oth}$ to 0.5. The remaining indirectly created cropland is assumed to have been created from pasture land ($s_{cr\_ind\_pa} = s_{cr\_ind} - s_{cr\_ind\_oth}$).

[11] US EPA. Federal Register. Vol. 75, No. 58. March 26, 2010, 14669-15320

Land that is indirectly converted to pasture land from forest land or other non-pasture land, s_{pa_ind} is given by the following expression.

Equation 8 $s_{pa\_ind} = f_{pa\_ind} \bullet s_{pa}$

The US EPA analysis provides little insight into the indirect land use change that may be driven by the conversion of pastureland to switchgrass; here we assume that the induced land use change is comparable to that from direct conversion of cropland, that is, f_{pa_ind} is also approximately 0.3.

4.3.1.5 Indirect Land Use Change: N_2O Emissions from Soils

Indirectly created cropland will consume additional nitrogen fertilizer. We use a variant of **Equation 1** for N_2O emissions from nitrogen fertilizers.

Equation 9 $N2O_{cr\_ind} = r_{N2O} \bullet N_{cr} \bullet s_{cr\_ind} / Y_{net\_sw}$

Fertilizer use can vary substantially by crop. Whereas switchgrass in this analysis is modeled as receiving 112 kg-N/ha/yr of nitrogen, nitrogen application rates in the US are typically 200 kg-N/ha/yr for corn, about 90 kg-N/ha/yr for cotton and typically 4 kg-N/ha/yr for soy. Given the substantial displacement of soy in the US EPA model (US EPA, 2010a), we estimate an average fertilizer use (N_{cr}) of 50 kg-N/ha/yr with a range from 10 to 100 kg-N/ha/yr. We assume the indirectly created pasture land does not use significant quantities of nitrogen fertilizer and, consequently, does not generate significant emissions of N_2O from nitrogen fertilizer use.

4.3.1.6 Indirect Land Use Change: Net CO_2 Emissions

In the section on direct land use change, we developed parameters for change in aboveground biomass, belowground biomass, and SOM carbon stocks, for land used as pasture and for land used as crops. We must note that the values used in this section should be considered very rough approximations because our assessment does not attempt to determine the location of indirect land use changes. For example, aboveground forest biomass in moist tropical regions can be an order of magnitude larger than aboveground forest biomass in drier regions. US EPA (2010) uses economic models of the global agricultural sector to estimate the location of land conversions. However, for the purposes of this case study we determined that published projections of the location of indirect land conversions were not appropriate for the scenario assessed in this report. Instead, we use the approximate values described below. Here we add parameters for the non-pasture, non-crop land involved in indirect conversion. This could include forest land, degraded lands, and marginal lands with a potentially wide range of carbon stocks. Forest land generally has the largest carbon stock and may be considered as an upper limit. For forest converted to cropland, drawing on estimates from Curtright et al. (2010) and from US EPA (2010), we estimate an aboveground biomass of approximately of 80 tonne C/ha. For belowground forest biomass, we estimate about 20 tonne C/ha. For SOM, we estimate that forests have 50 tonne C/ha and that row crops have 40 tonne C/ha. The carbon contents of aboveground biomass and belowground biomass for crop land and pasture land were given previously in the sections on direct land use change.

The US EPA's analysis suggests that the soil carbon stock of the average "other" (i.e., non-pasture, non-crop) land involved in indirect land use change is about half that of the above values for forest, suggesting that the model results largely draw on low-carbon-stock lands for this portion of indirect land use change. Except for carbon in SOM, we use these values in our estimates. The value we used for carbon in SOM is discussed below.

4.3.1.6.1 Indirect Net CO_2 Emissions for Above Ground Biomass

For above ground biomass, we use a variant of **Equation 3**. For conversion of cropland from "other land", the change in carbon in the above ground biomass stock (expressed as an equivalent mass of CO_2) can be calculated using the following equation:

Equation 10 $CO_2e_{above\_cr\_oth} = -[(f_{b\_cr} \bullet T_{b\_ag} \bullet Y_{cr} \bullet C_{cr}) - C_{above\_oth}] \bullet s_{cr\_ind\_oth} \bullet (CO_2/C) \bullet 1000$ kg/tonne / $(Y_{net\_sw} \bullet T)$

For conversion of cropland from pasture land, the change in carbon in the above ground biomass stock (expressed as an equivalent mass of CO_2) can be calculated using the following equation:

Equation 11 $CO_2e_{above\_cr\_pa} = -[(f_{b\_cr} \bullet T_{b\_ag} \bullet Y_{cr} \bullet C_{cr}) - (f_{b\_pa} \bullet T_{b\_ag} \bullet Y_{pa} \bullet C_{pa})] \bullet s_{cr\_ind\_pa} \bullet (CO_2/C) \bullet$ 1000 kg/tonne / $(Y_{net\_sw} \bullet T)$

For conversion of pasture land from "other land," the change in carbon in the aboveground biomass stock (expressed as an equivalent mass of CO_2) can be calculated using the following equation:

Equation 12 $CO_{2eabove\_pa\_oth} = -[(f_{b\_pa} \bullet T_{b\_ag} \bullet Y_{pa} \bullet C_{pa}) - C_{above\_oth}] \bullet s_{pa\_ind} \bullet (CO_2/C) \bullet 1000$ kg/tonne / $(Y_{net\_sw} \bullet T)$

The variables in **Equations 10**, **11,** and **12** have all been defined previously. The variables $CO_2e_{above\_cr\_oth}$, $CO_2e_{above\_cr\_pa}$, and $CO_2e_{above\_pa\_oth}$ have units of kg CO_2/tonne biomass ready for transport.

4.3.1.6.2 Indirect Net CO_2 Emission for Belowground Biomass

For belowground biomass, we use a variant of **Equation 4**. For conversion of cropland from "other land," the change in carbon in the belowground biomass stock (expressed as an equivalent mass of CO_2) can be calculated using the following:

Equation 13 $CO_{2ebelow\_cr\_oth} = -(CO_2/C) \bullet 1000$ kg/tonne $\bullet (C_{root\_cr} - C_{root\_oth}) \bullet s_{cr\_ind\_oth}$ / $(Y_{net\_sw} \bullet T)$

For conversion of cropland from pasture land, the change in carbon in the belowground biomass stock (expressed as an equivalent mass of CO_2) can be calculated as follows:

Equation 14 $CO_{2ebelow\_cr\_pa} = -(CO_2/C) \bullet 1000$ kg/tonne $\bullet (C_{root\_cr} - C_{root\_pa}) \bullet s_{cr\_ind\_pa}$ / $(Y_{net\_sw} \bullet T)$

For conversion of pasture land from "other land," the change in carbon in the belowground biomass stock (expressed as an equivalent mass of CO_2) can be calculated as follows:

Equation 15 $CO_{2ebelow\_pa\_oth} = -(CO_2/C) \bullet 1000$ kg/tonne $\bullet (C_{root\_pa} - C_{root\_oth}) \bullet s_{pa\_ind}$ / $(Y_{net\_sw} \bullet T)$

The variables in **Equations 13**, **14**, and **15** have all been defined previously. The variables $CO_2e_{below\_cr\_oth}$, $CO_2e_{below\_cr\_pa}$, and $CO_2e_{below\_pa\_oth}$ have units of kg CO_2/dry tonne biomass ready for transport.

4.3.1.6.3 Indirect Net CO_2 Emissions for SOM

For SOM, we use a variant of **Equation 4**. For conversion of cropland from "other land," the change in carbon in the SOM stock (expressed as an equivalent mass of CO_2) can be given by:

Equation 16 $CO_2e_{soil\_cr\_oth} = -(CO_2/C) \bullet 1000$ kg/tonne $\bullet \Delta C_{soil\_oth\_cr} \bullet s_{cr\_ind\_oth}$ / $(Y_{net\_sw} \bullet T)$

For conversion of cropland from pasture land, the change in carbon in the SOM stock (expressed as an equivalent mass of CO_2) can be given by:

Equation 17 $CO_2e_{soil\_cr\_pa} = -(CO_2/C) \cdot 1000 \text{ kg/tonne} \cdot \Delta C_{soil\_pa\_cr} \cdot s_{cr\_ind\_pa} / (Y_{net\_sw} \cdot T)$

For conversion of pasture land from "other land", the change in carbon in the SOM stock (expressed as an equivalent mass of CO_2) can be given by:

Equation 18 $CO_2e_{soil\_pa\_oth} = -(CO_2/C) \cdot 1000 \text{ kg/tonne} \cdot \Delta C_{soil\_oth\_pa} \cdot s_{pa\_ind} / (Y_{net\_sw} \cdot T)$

The variables $CO_2e_{soil\_cr\_oth}$, $CO_2e_{soil\_cr\_pa}$, and $CO_2e_{soil\_pa\_oth}$ have units of kg CO_2/dry tonne biomass ready for transport. The variables $\Delta C_{soil\_oth\_cr}$, $\Delta C_{soil\_pa\_cr}$, and $\Delta C_{soil\_oth\_pa}$ are the change in SOM on average as the land changes from one land use ("other" or oth, pasture or pa) to either crop land (cr) or pasture (pa). The change in SOM as the land shifts from pasture to cropland, $\Delta C_{soil\_pa\_cr}$, is assumed to be -21.5 tonnes C/ha, the same as for direct land use, while the change in SOM as the land shifts from "other land" to cropland $\Delta C_{soil\_oth\_cr}$ is assumed to be half this value or -10.7625 tonnes C/ha. The change in SOM as the land shifts from "other land" to pasture, $\Delta C_{soil\_oth\_pa}$, is calculated as $\Delta C_{soil\_oth\_cr} - \Delta C_{soil\_pa\_cr}$ or 10.7625 tonnes C/ha. The minus sign indicates the change from "other" land or pasture land to crop land causes emissions of CO_2 to the atmosphere rather than sequestration of carbon in biomass or SOM. The positive result for $\Delta C_{soil\_oth\_pa}$ indicates that carbon is sequestered in SOM.

4.3.1.6.4 Total Indirect Net CO_2 Emissions

The change in the total carbon stock due to indirect land use change can be expressed as the sum of the changes in carbon in the three carbon stocks in the soil-plant system: the above ground biomass stock, the below ground biomass stock, and the SOM stock. This is given by **Equation 19**.

Equation 19 $CO_2e_{stock} = (CO_{2above\_cr\_oth} + CO_2e_{below\_cr\_oth} + CO_2e_{soil\_cr\_oth}) + (CO_{2above\_cr\_pa} + CO_2e_{below\_cr\_pa} + CO_2e_{soil\_cr\_pa}) + (CO_{2above\_pa\_oth} + CO_2e_{below\_pa\_oth} + CO_2e_{soil\_pa\_oth})$

The variable CO_2e_{stock} is the total carbon stock with units of kg CO_2/dry tonne biomass delivered.

4.3.1.7 Key Modeling Variables

The key variables with respect to the emissions of GHGs associated with direct and indirect land use are presented in Table 40. For each variable, the best estimate is presented, along with the minimum value, maximum value, most likely value and the distribution assumed for the variable.

The variable representing the "Share of land previously crop land" was estimated based on the study by Eppink et al. (2010) discussed previously. It was assumed that this variable could be as low as 15 percent or as high as 40 percent, with the best estimate from Eppink et al. (2010) of 23.9 percent. A triangular distribution was assumed for this variable. The variable representing the fraction of applied nitrogen fertilizer that can be emitted as N_2O was assumed to be approximated by a triangular distribution based the range of emission factors discussed previously for this variable.

For many of the variables in Table 40, data were not readily available to estimate uncertainty, and/or to evaluate a most likely value. For these variables, it was assumed the uncertainty can be characterized by a uniform distribution where the best estimate might be higher or lower by 10 percent. For all these variables, the most likely value is set to the average, although, technically, any value between the minimum and maximum of a uniform distribution is equally likely.

Several variables ["Crop pre-harvest yield," "Pasture pre-harvest yield," "Fraction of switchgrass yield assumed to be present during time period T_bio_ag (1 year)," "Fraction of crop yield

assumed to be present during time period T_bio_ag (1 year)," "Fraction of pasture yield assumed to be present during time period T_bio_ag (1 year)," "Fraction of crop land converted directly to switchgrass that is indirectly converted back to crop land," "Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land," "Carbon in above ground 'other' (including forest) biomass," and "Carbon in "other" biomass (including forest) roots"] were assumed to be uncertain but their uncertainty is believed to be greater. For these variables, it was assumed the uncertainty can be characterized by a uniform distribution where the best estimate might be higher or lower by a number greater than 10 percent.

As indicated in Table 40, some of the variables in this table are used in both the direct and indirect land use analysis. One variable is only used in the direct land use analysis and four variables are only used in the indirect land use analysis.

Table 40. Key Modeling Variables for Direct and Indirect Land Use (LC Stage #1c)

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-Direct and Indirect Land Use							
Share of land previously crop land		23.9%	15.0%	40.0%	23.9%	Triangular	The best estimate is from Eppink et al. (2010); the minimum and maximum values are based on engineering judgment
N_2O emissions from nitrogen fertilizer	kg N_2O/kg N	0.02	0.003	0.05	0.02	Triangular	Based on estimated rates from the literature
Crop pre-harvest yield	tonne/ha/yr	1	0.8	1.2	1	Uniform	Assumes that yield is -10% to +10% of best estimate
Pasture pre-harvest yield	tonne/ha/yr	5	4	6	5	Uniform	Assumes that yield is -10% to +10% of best estimate
Fraction of switchgrass yield assumed to be present during time period T_bio_ag (1year)		0.5	0.4	0.6	0.5	Uniform	Assumes that fraction of switchgrass yield is -20% to +20% of best estimate
Fraction of crop yield assumed to be present during time period T_bio_ag (1 year)		0.5	0.4	0.6	0.5	Uniform	Assumes that fraction of switchgrass yield is -20% to +20% of best estimate
Fraction of pasture yield assumed to be present during time period T_bio_ag (1 year)		0.5	0.4	0.6	0.5	Uniform	Assumes that fraction of switchgrass yield is -20% to +20% of best estimate
Carbon fraction of dry crops	kg C/kg row crops	0.40	0.36	0.44	0.40	Uniform	Assumes that carbon fraction is -10% to +10% of best estimate
Carbon fraction of dry pasture	kg C/kg pasture	0.40	0.36	0.44	0.40	Uniform	Assumes that carbon fraction is -10% to +10% of best estimate
Carbon in crop roots	tonne C/ha	2.0	1.8	2.2	2.0	Uniform	Assumes that carbon in roots is -10% to +10% of best estimate
Carbon in pasture roots	tonne C/ha	4.8	4.3	5.3	4.8	Uniform	Assumes that carbon in roots is -10% to +10% of best estimate
Input Parameters-Direct Land Use Only							
Carbon in switchgrass roots	tonne C/ha	4.9	4.4	5.4	4.9	Uniform	Assumes that carbon in roots is -10% to +10% of best estimate

Table 40. Key Modeling Variables for Direct and Indirect Land Use (LC Stage #1c) *(Cont'd)*

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-Indirect Land Use Only							
Fraction of crop land converted directly to switchgrass that is indirectly converted back to crop land		0.3	0.2	0.4	0.3	Uniform	Assumes that fraction of land is -33% to +33% of best estimate
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land		0.3	0.2	0.4	0.3	Uniform	Assumes that fraction of land is -33% to +33% of best estimate
Carbon in aboveground "other" (including forest) biomass	tonne C/ha	40	30	50	40	Uniform	Assumes that carbon mass is -25% to +25% of best estimate
Carbon in "other" biomass (including forest) roots	tonne C/ha	10	8	12	10	Uniform	Assumes that carbon mass is -20% to +120% of best estimate

4.3.2 Data Quality Assessment

The results of unit process data quality evaluation for Stage #1c are provided in Table 41. Data quality indicators and life cycle significance determinations are listed for unit processes included in the model of this stage.

Both direct and indirect land use are significant processes in the study and score below quality requirements. Therefore, key input variables used to calculate direct and indirect land use effects are included in sensitivity analysis.

Table 41. Land Use (LC Stage #1c) Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Life Cycle Significance of Process
1	Direct Land Use	4,3,1,3,1	-0.45%
1	Indirect Land Use	3,5,1,4,1	1.82%

4.3.3 Results

This section presents the life cycle GHG emissions for LC Stage #1c. The first part of this section presents the deterministic results for direct and indirect land use. The second part of this section presents the range in GHG emissions when the variables described in the Key Modeling Variables section are allowed to be varied in a probabilistic simulation. The third part of this section presents a sensitivity analysis for the GHG emissions from these uncertain variables.

4.3.3.1 Deterministic Greenhouse Gas Emissions

The deterministic results for LC Stage #1c are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S1c.Summ, which presents the input flows, output flows (products and co-products) and GHG emissions for this stage. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the functional unit. The GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are also presented in this sheet. Table 42 presents the life cycle GHG emissions for LC Stage #1c for direct and indirect land use. This table presents the total emissions of 1) biogenic carbon dioxide, and 2) nitrous oxide. The second column in the table presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the IPCC 2007, IPCC 2001, and IPCC 1996 estimates, respectively.

As indicated in Table 42, direct land results in negative CO_2e emissions indicating that direct land use extracts more carbon dioxide from the air than is released into the air. This is primarily because the switchgrass planted on land previously used for crops builds up the carbon in aboveground biomass, belowground biomass, and SOM relative to crop land. Switchgrass planted on land previously used for pasture also builds up the carbon in aboveground biomass and belowground biomass relative to pasture land. CO_2e emissions of N_2O from increased fertilizer use as compared to fertilizer use on the directly displaced crop and pasture land almost equals the net storage of CO_2 in the three biomass pools.

Indirect land use, in contrast results in net CO_2e emissions to the atmosphere. The crop land and pasture land that displaces “other land” (including forest land) results in reduced carbon storage

in aboveground and belowground biomass and slightly increased carbon storage in SOM, resulting in net emissions of CO_2 to the atmosphere. CO_2e emissions of N_2O from increased fertilizer use as compared to fertilizer use on the "other land" and pasture land also contributes to the CO_2e emissions to the atmosphere.

For comparison, US EPA (2010) estimates total land use change emissions (direct and indirect) of 86,000 g CO_2e per tonne of switchgrass, with a 95 percent confidence range from 20,900 to 159,000 g CO_2e per tonne of switchgrass. US EPA (2010) reports N_2O emissions together with other farming inputs (e.g., diesel use). US EPA (2010) also estimates total domestic and international fertilizer and farm inputs of 39,700 g CO_2e per tonne of switchgrass. US EPA (2010) uses IPCC 2001 GWP.

Table 42. LC Stage #1c GHG Emissions for Direct and Indirect Land Use (per Tonne Switchgrass Ready for Transport)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/tonne SG)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne SG) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne SG) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne SG) (IPCC 1996 GWP)
Biogenic CO_2 – Direct Land Use	-110,000	-110,000	-110,000	-110,000
Biogenic CO_2 – Indirect Land Use	150,000	150,000	150,000	150,000
Biogenic CO_2 – Subtotal	43,000	43,000	43,000	43,000
N_2O – Direct Land Use	230	69,000	68,000	71,000
N_2O – Indirect Land Use	8	2,500	2,400	2,600
N_2O – Subtotal	240	71,000	70,000	74,000
Direct Land Use – Total		-41,000	-42,000	-39,000
Indirect Land Use – Total		150,000	150,000	150,000
Grand Total		110,000	110,000	110,000

Note: Subtotals and totals may not sum exactly due to rounding.

4.3.3.2 Probabilistic Uncertainty Analysis

In an attempt to quantify the influence on the calculated GHG emissions of uncertainty in the variables presented in Table 40, probabilistic simulations were performed for total life cycle GHG emissions using the IPCC 2007 global warming potentials. CO_2 equivalent emissions were calculated relative to the stage reference flow of 1 tonne of switchgrass ready for transport. Separate probabilistic results were generated for direct land use, indirect land use, and total direct and indirect land use. To facilitate the plotting of the results, the amount of CO_2e sequestered by land use was calculated rather than the amount of CO_2e emitted. The amount of CO_2e sequestered is the negative of the amount of CO_2e emitted.

Table 43 presents the statistics for the CO_2e emissions developed from the simulations. Figure 18 through Figure 20 present the cumulative distribution and probability density function for CO_2 equivalent sequestration for direct land use, CO_2 equivalent emissions for indirect land use, and CO_2 emissions for direct and indirect land use, respectively, relative to the LC Stage #1c reference flow. In Figure 18 through Figure 20, the vertical scale on the left is for the probability density function and the vertical scale on the right is for the cumulative distribution.

For direct land use, the total CO_2e sequestered relative to the reference flow range from -87 to 140 kg CO_2e/tonne switchgrass, with a median value of 35 kg CO_2e/tonne switchgrass, a mean

of 32 kg CO_2e/tonne switchgrass, and a standard deviation of 39 kg CO_2e/tonne switchgrass. Eighty percent of the distribution lies between -21 and 81 kg CO_2e/tonne switchgrass, and the middle fifty percent of the distribution lies between 5.8 and 58 kg CO_2e/tonne switchgrass.

For indirect land use, the total CO_2e emitted relative to the reference flow ranges from 77 to 250 kg CO_2e/tonne switchgrass, with a median value of 150 kg CO_2e/tonne switchgrass, a mean of 150 kg CO_2e/tonne switchgrass and a standard deviation of 30 kg CO_2e/tonne switchgrass. Eighty percent of the distribution lies between 120 and 200 kg CO_2e/tonne switchgrass, and the middle fifty percent of the distribution lies between 130 and 180 kg CO_2e/tonne switchgrass.

For both direct and indirect land use, the total CO_2e emitted relative to the reference flow ranges from -14 to 290 kg CO_2e/tonne switchgrass, with a median value of 120 kg CO_2e/tonne switchgrass, a mean of 120 kg CO_2e/tonne switchgrass and a standard deviation of 50 kg CO_2e/tonne switchgrass. Eighty percent of the distribution lies between 58 and 190 kg CO_2e/tonne switchgrass, and the middle fifty percent of the distribution lies between 88 and 160 kg CO_2e/tonne switchgrass.

Table 43. LC Stage #1c: Probabilistic Uncertainty Analysis; Statistics for Non-Biogenic CO_2e Emissions

Statistical Parameter	Mass of GHG Sequestered by Direct Land Use Changes (kg CO_2e/tonne switchgrass) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere by Indirect Land Use Changes (kg CO_2e/tonne switchgrass) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere by Direct and Indirect Land Use Changes (kg CO_2e/tonne switchgrass) (IPCC 2007 GWP)
Minimum	-87	77	-14
10%	-21	120	58
25%	5.8	130	88
Median (50%)	35	150	120
75%	58	180	160
90%	81	200	190
Maximum	140	250	290
Mean	32	150	120
Mode	49	160	120
Stand. Deviation	39	30	49

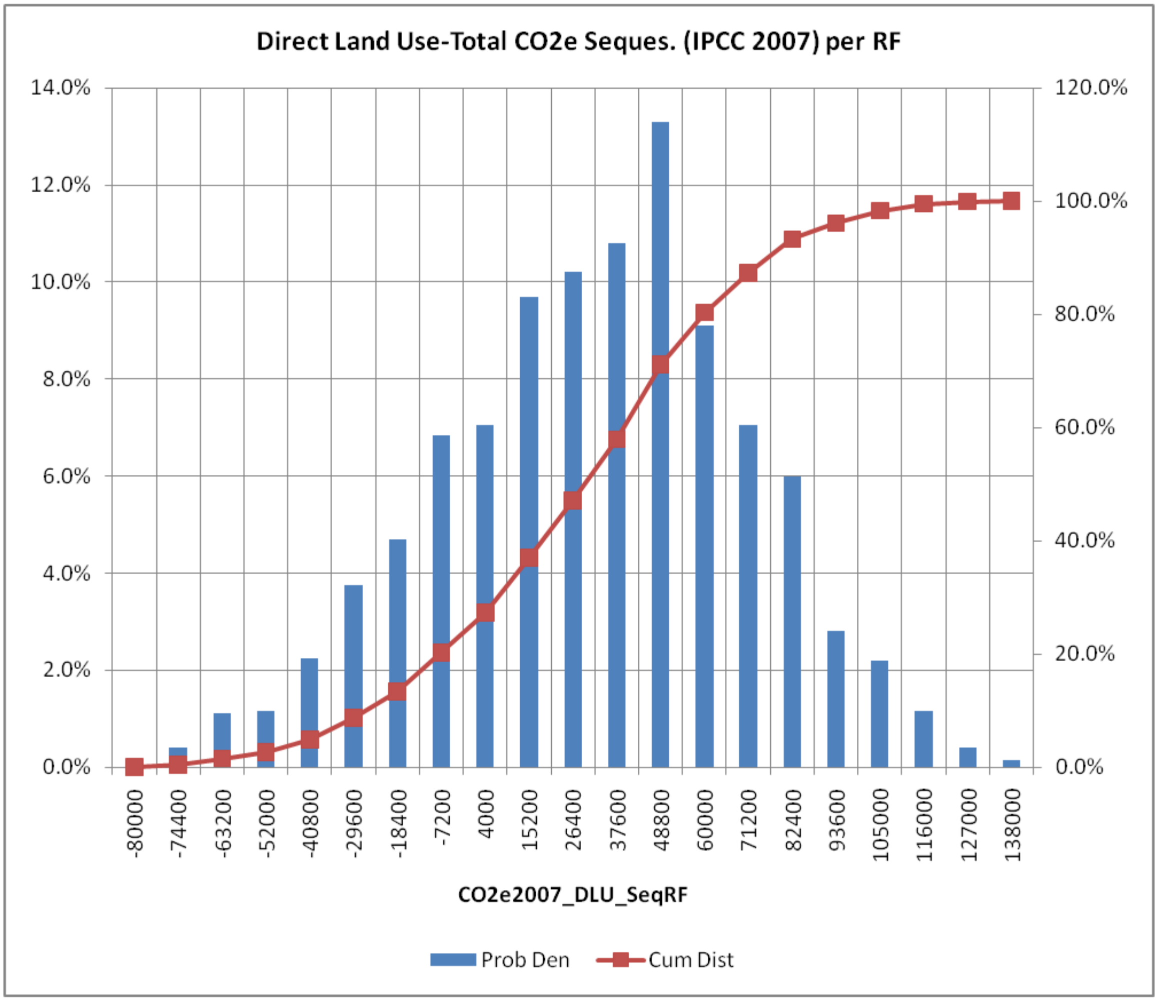


Figure 18. LC Stage #1c Probability Density Function and Cumulative Distribution of CO_2e Sequestered by Direct Land Use Changes (Using IPCC 2007 GWP) (per Tonne Switchgrass Ready for Transport)

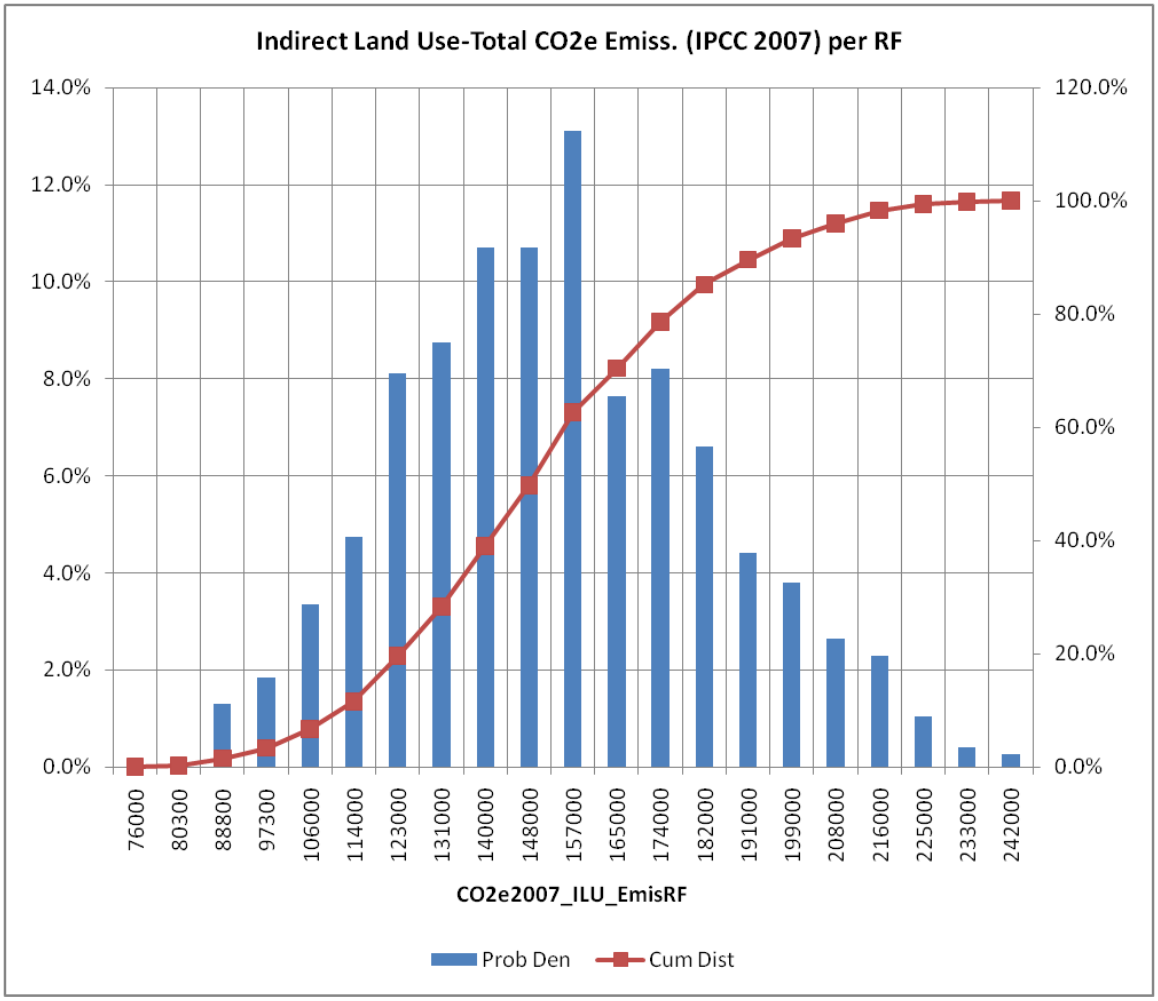


Figure 19. LC Stage #1c Probability Density Function and Cumulative Distribution of CO_2e Emissions by Indirect Land Use Changes (Using IPCC 2007 GWP) (per Tonne Switchgrass Ready for Transport)

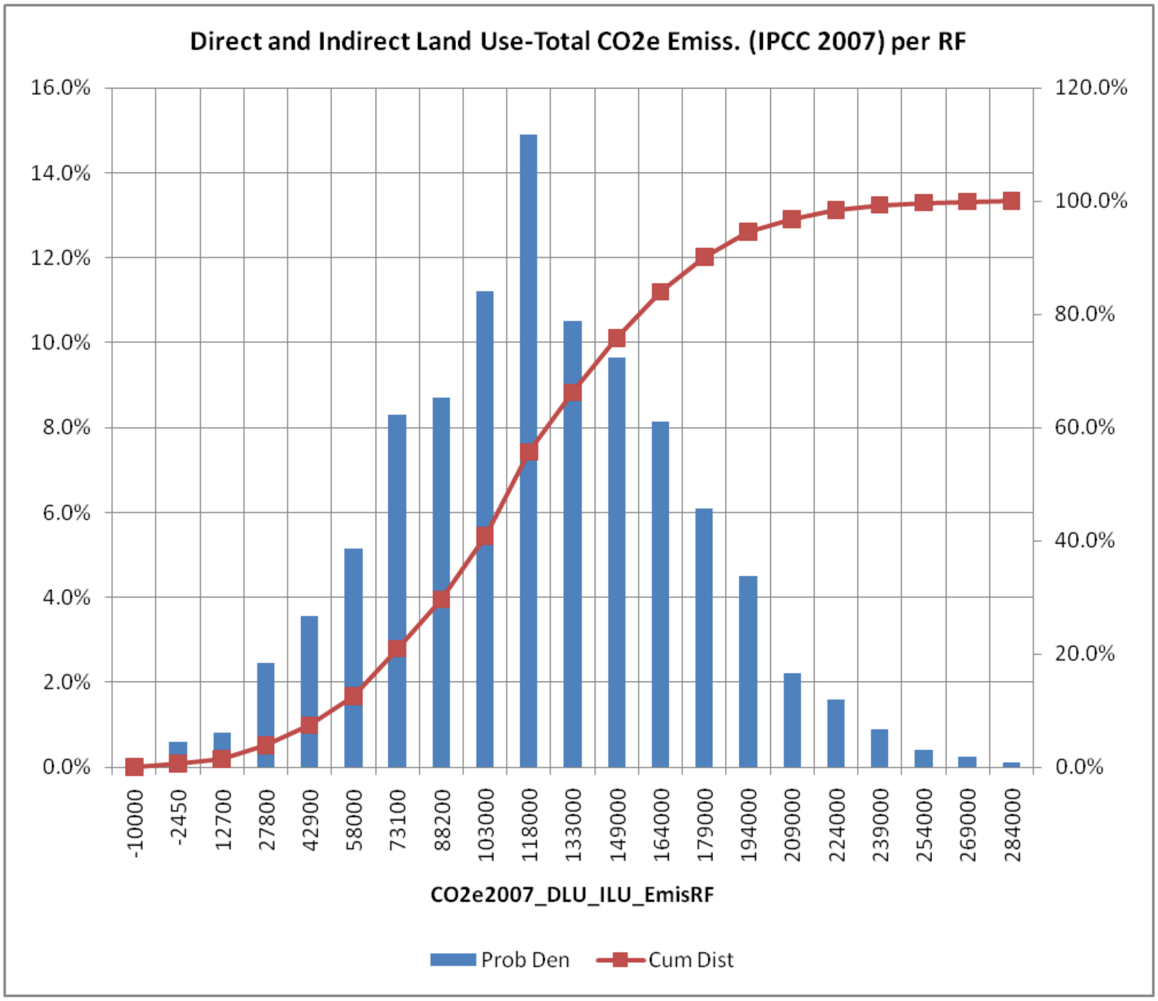


Figure 20. LC Stage #1c Probability Density Function and Cumulative Distribution of CO_2e Emissions by Direct and Indirect Land Use Changes (Using IPCC 2007 GWP) (per Tonne Switchgrass Ready for Transport)

4.3.3.3 Sensitivity Analysis

In the sensitivity analysis, the total CO_2e emissions using the IPCC 2007 global warming potentials were calculated for each key variable in Table 40. For direct land use, Table 44 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions. The Absolute Difference for each key variable is also shown, and key variables are listed from highest to lowest based on their Absolute Difference. This same result is presented graphically for direct land use changes in the tornado chart presented in Figure 21. The results in Table 44 and Figure 21 show total CO_2e emissions, not CO_2e sequestered.

The variable that has the most influence on the calculated emissions is the "N2O emissions from fertilizer." The next most important variable is the "Share of land previously cropland." All other key variables have a negligible influence on total CO_2e emissions from direct land use changes.

Table 44. Sensitivity Analysis Results for Total CO_2e Emissions for Stage #1c for Direct Land Use Changes (Using IPCC 2007 GWP) (g CO_2e/Tonne Switchgrass Ready for Transport)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/tonne switchgrass)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
N_2O emissions from nitrogen fertilizer	r_N2O	kg N_2O/kg N	0.02	0.003	0.05	-95700	65200	161000
Share of land previously crop land	s_cr		0.239	0.15	0.4	-3120	-99700	96600
Fraction of switchgrass yield assumed to be present during time period T_bio_ag (1year)	f_b_sw		0.5	0.4	0.6	-30600	-44400	13800
Carbon in switchgrass roots	C_root_sw	tonne C/ha	4.9	4.41	5.39	-30600	-44400	13700
Carbon in pasture roots	C_root_pa	tonne C/ha	4.8	4.32	5.28	-42600	-32400	10200
Fraction of pasture yield assumed to be present during time period T_bio_ag (1 year)	f_b_pa		5	4	6	-39600	-35400	4270
Carbon fraction of dry pasture	C_pa	kg C/kg pasture	0.5	0.4	0.6	-39600	-35400	4270
Pasture pre-harvest yield	Y_pa	tonne/ha/yr	0.4	0.36	0.44	-38600	-36400	2130
Carbon in crop roots	C_root_cr	tonne C/ha	2	1.8	2.2	-38200	-36800	1340
Fraction of crop yield assumed to be present during time period T_bio_ag (1 year)	f_b_cr		1	0.8	1.2	-37800	-37200	536
Crop pre-harvest yield	Y_cr	tonne/ha/yr	0.5	0.4	0.6	-37600	-37400	268
Carbon fraction of dry crops	C_cr	kg C/kg row crops	0.4	0.36	0.44	-37600	-37400	134

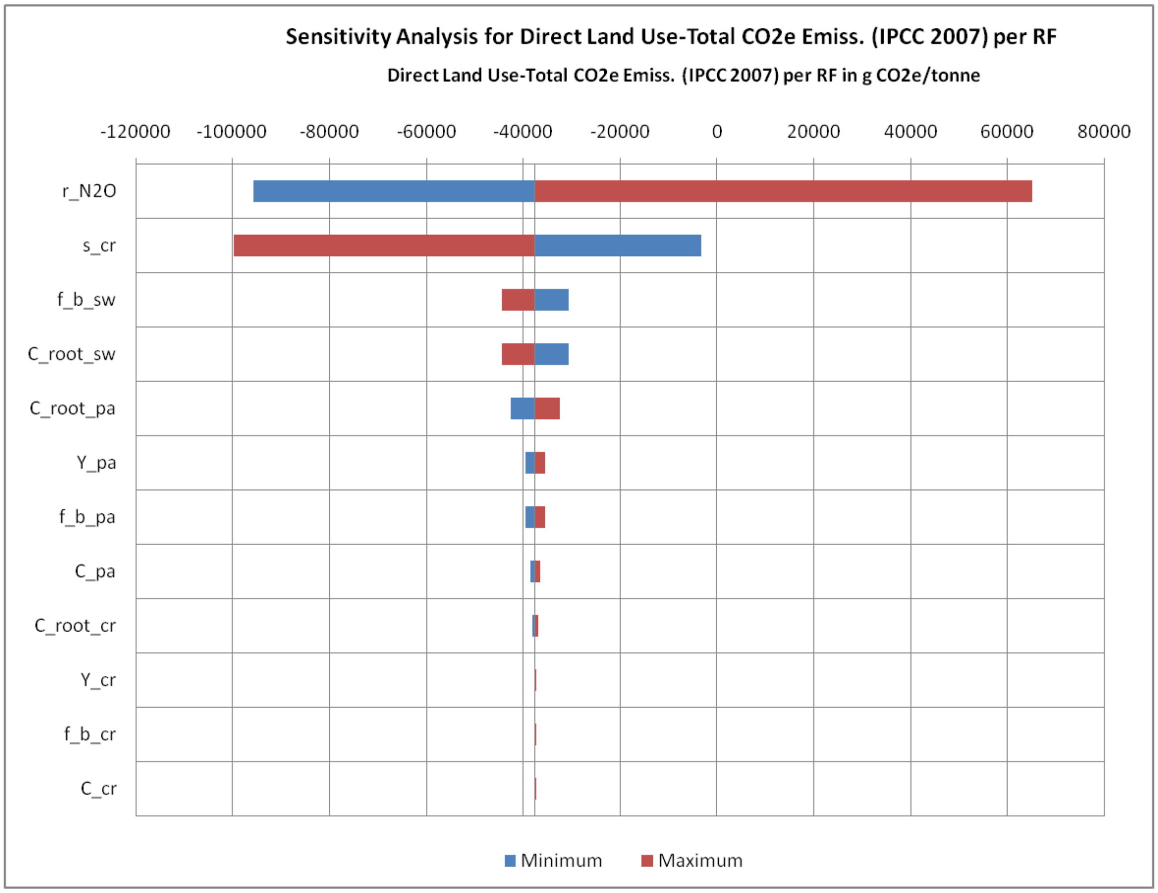


Figure 21. LC Stage #1c Sensitivity Analysis Results for Total CO_2e Emissions for Direct Land Use Changes (Using IPCC 2007 GWP) (g CO_2e per Dry Tonne Switchgrass Ready for Transport)

For indirect land use, Table 45 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions. The Absolute Difference for each key variable is also shown, and key variables are listed from highest to lowest based on their Absolute Difference. This same result is presented graphically for indirect land use changes in the tornado chart presented in Figure 22.

The variables that have the most influence on the calculated emissions are the "Carbon in above ground 'other' (including forest) biomass" and "Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land." Other important variables are the "Share of land previously crop land," "Fraction of crop land converted directly to switchgrass that is indirectly converted back to crop land," "Carbon in 'other' biomass (including forest) roots," and "N_2O emissions from nitrogen fertilizer." All other key variables have a negligible influence on total CO_2e emissions from indirect land use changes.

Table 45. Sensitivity Analysis Results for Total CO_2e Emissions for Stage #1c for Indirect Land Use Changes (Using IPCC 2007 GWP) (g CO_2e/Dry Tonne Switchgrass Ready for Transport)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/tonne switchgrass)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Carbon in above ground "other" (including forest) biomass	C_above_oth	tonne C/ha	40	30	50	114000	189000	74100
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind		0.3	0.2	0.4	116000	187000	71300
Share of land previously crop land	f_cr_ind		0.3	0.2	0.4	137000	166000	29700
Fraction of crop land converted directly to switchgrass that is indirectly converted back to crop land	C_root_oth	tonne C/ha	10	8	12	144000	159000	14800
Carbon in "other" biomass (including forest) roots	s_cr		0.239	0.15	0.4	147000	159000	11400
N_2O emissions from nitrogen fertilizer	r_N2O	kg N_2O/kg N	0.02	0.003	0.05	149000	155000	5760
Carbon in pasture roots	C_root_pa	tonne C/ha	4.8	4.32	5.28	153000	150000	2590
Fraction of pasture yield assumed to be present during time period T_bio_ag (1 year)	Y_pa	tonne/ha/yr	5	4	6	152000	151000	1080
Carbon fraction of dry pasture	f_b_pa		0.5	0.4	0.6	152000	151000	1080
Pasture pre-harvest yield	C_pa	kg C/kg pasture	0.4	0.36	0.44	152000	151000	540
Carbon in crop roots	C_root_cr	tonne C/ha	2	1.8	2.2	152000	151000	402
Fraction of crop yield assumed to be present during time period T_bio_ag (1 year)	Y_cr	tonne/ha/yr	1	0.8	1.2	152000	151000	80.4
Carbon fraction of dry crops	f_b_cr		0.5	0.4	0.6	152000	151000	80.4
Crop pre-harvest yield	C_cr	kg C/kg row crops	0.4	0.36	0.44	152000	151000	40.2
Fraction of switchgrass yield assumed to be present during time period T_bio_ag (1year)	f_b_sw		0.5	0.4	0.6	152000	152000	0

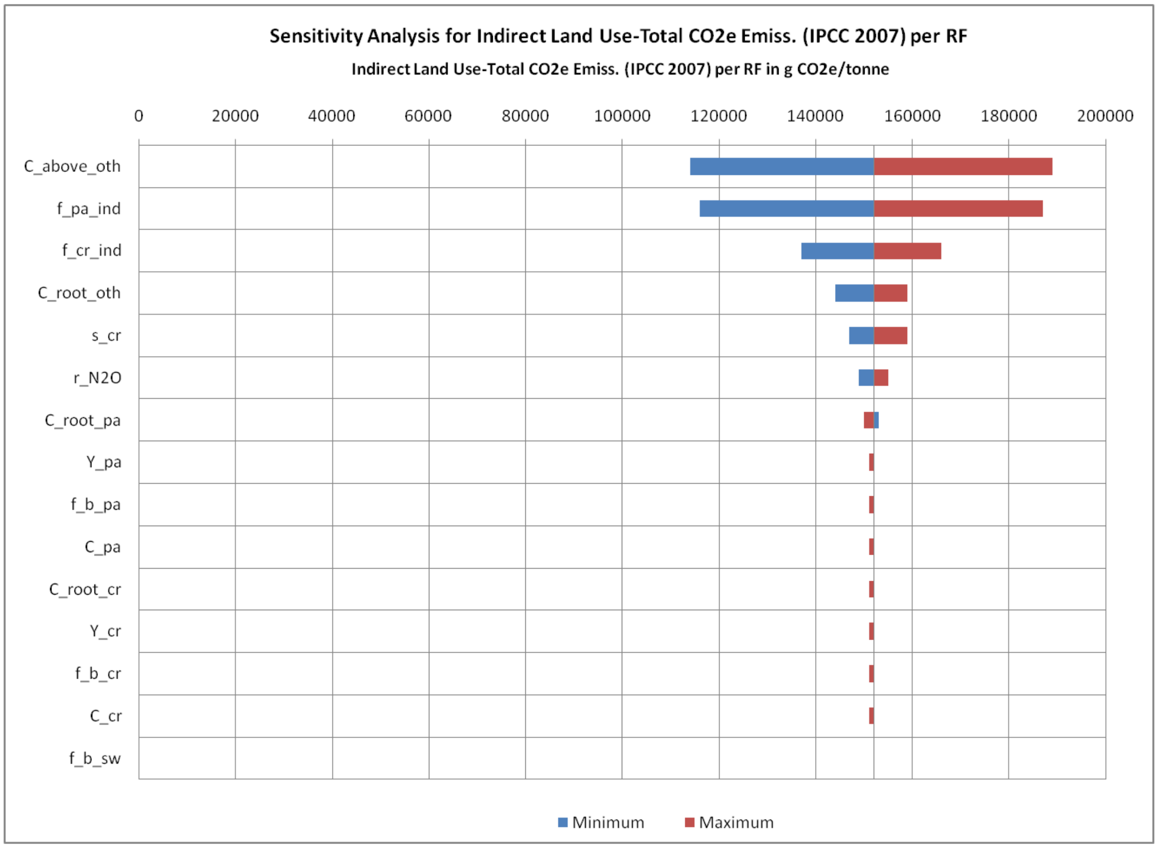


Figure 22. LC Stage #1c Sensitivity Analysis Results for Total CO_2e Emissions for Indirect Land Use Changes (Using IPCC 2007 GWP) (g CO_2e per Dry Tonne Switchgrass Ready for Transport)

For the total of direct and indirect land use, Table 46 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions. The Absolute Difference for each key variable is also shown, and key variables are listed from highest to lowest based on their Absolute Difference. This same result is presented graphically for indirect land use changes in the tornado chart presented in Figure 23.

The variables that have the most influence on the calculated emissions from direct and indirect land use changes are “N2O emissions from nitrogen fertilizer” and “Share of land previously crop land.” Although not as influential as these first two variables, other important variables “Carbon in above ground "other" (including forest) biomass,” “Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land,” “Fraction of switchgrass yield assumed to be present during time period T_bio_ag (1year),” and “Carbon in switchgrass roots.” All other key variables have a negligible influence on total CO_2e emissions from direct and indirect land use changes.

Table 46. Sensitivity Analysis Results for Total CO_2e Emissions for Stage #1c for Direct and Indirect Land Use Changes (Using IPCC 2007 GWP) (g CO_2e/Dry Tonne Switchgrass Ready for Transport)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/tonne switchgrass)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
N_2O emissions from nitrogen fertilizer	r_N2O	kg N_2O/kg N	0.02	0.003	0.05	53700	220000	167000
Share of land previously crop land	s_cr		0.239	0.15	0.4	144000	59100	85200
Carbon in above ground "other" (including forest) biomass	C_above_oth	tonne C/ha	40	30	50	77000	151000	74100
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind		0.3	0.2	0.4	78300	150000	71300
Fraction of switchgrass yield assumed to be present during time period T_bio_ag (1year)	f_cr_ind		0.3	0.2	0.4	99200	129000	29700
Carbon in switchgrass roots	C_root_oth	tonne C/ha	10	8	12	107000	121000	14800
Fraction of crop land converted directly to switchgrass that is indirectly converted back to crop land	f_b_sw		0.5	0.4	0.6	121000	107000	13800
Carbon in pasture roots	C_root_sw	tonne C/ha	4.9	4.41	5.39	121000	107000	13700
Carbon in "other" biomass (including forest) roots	C_root_pa	tonne C/ha	4.8	4.32	5.28	110000	118000	7650
Fraction of pasture yield assumed to be present during time period T_bio_ag (1 year)	Y_pa	tonne/ha/yr	5	4	6	112000	116000	3190
Carbon fraction of dry pasture	f_b_pa		0.5	0.4	0.6	112000	116000	3190
Pasture pre-harvest yield	C_pa	kg C/kg pasture	0.4	0.36	0.44	113000	115000	1590
Carbon in crop roots	C_root_cr	tonne C/ha	2	1.8	2.2	114000	114000	938
Crop pre-harvest yield	Y_cr	tonne/ha/yr	1	0.8	1.2	114000	114000	456
Fraction of crop yield assumed to be present during time period T_bio_ag (1 year)	f_b_cr		0.5	0.4	0.6	114000	114000	188
Carbon fraction of dry crops	C_cr	kg C/kg row crops	0.4	0.36	0.44	114000	114000	93.8

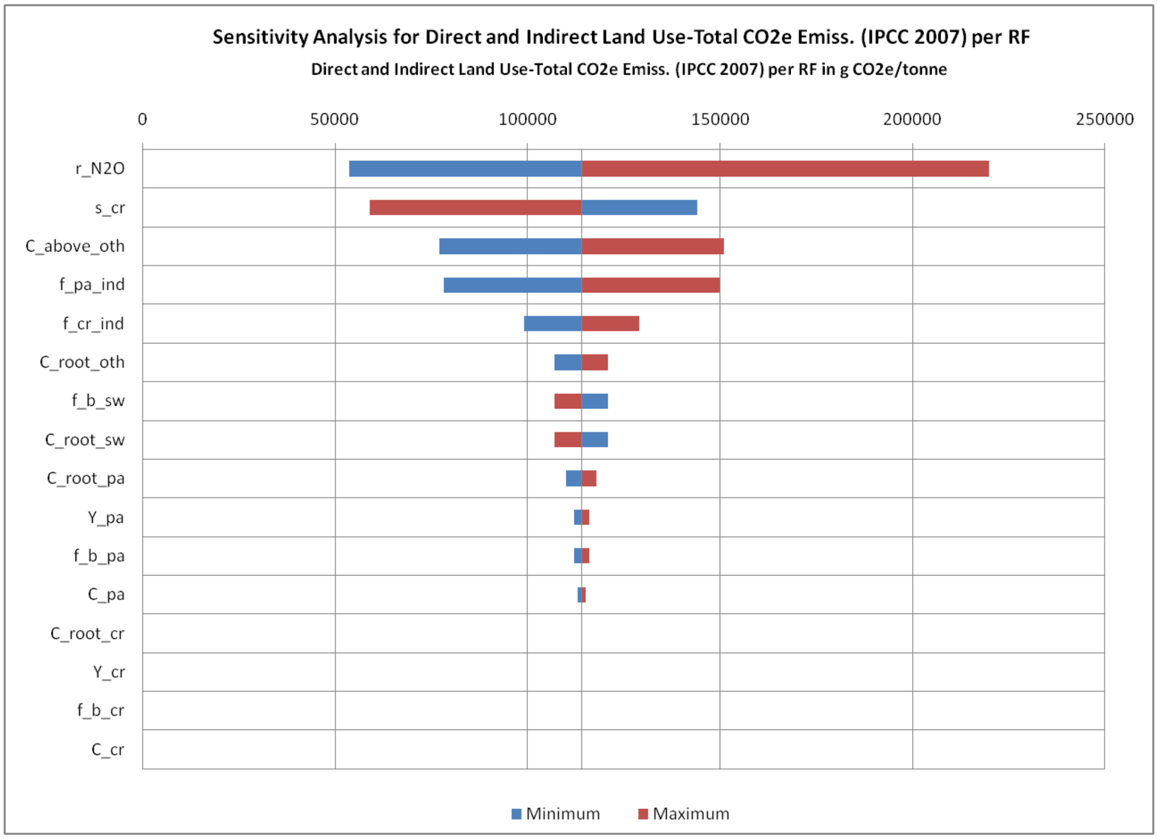


Figure 23. LC Stage #1c Sensitivity Analysis Results for Total CO_2e Emissions for Direct and Indirect Land Use Changes (Using IPCC 2007 GWP) (g CO_2e per Tonne Switchgrass Ready for Transport)

5.0 LC STAGE #2: RAW MATERIAL TRANSPORT

Both coal and switchgrass require transport to the CBTL facility. Illinois No. 6 coal is transported by rail under LC Stage #2a, from the coal mine to the CBTL facility. Switchgrass biomass is transported by semi truck under LC Stage #2b, from agricultural production/storage areas, to the CBTL facility.

5.1 Coal Transport (LC Stage #2a)

LC Stage #2a incorporates the process of transporting the Illinois No. 6 coal by rail, starting at the mine and ending with coal unloaded at the CBTL facility. Illinois No.6 Coal is transported by rail a distance of 200 miles, and construction of a 25-mile rail spur between the primary rail line and the CBTL facility is included.

5.1.1 Modeling Approach and Data Sources

Mined coal is transported by rail from the coal mine in southern Illinois to the CBTL facility in north central or north western Missouri, a roundtrip distance of approximately 400 miles. For this study, a unit train is defined as five locomotives pulling 100 railcars loaded with coal. The locomotives are each powered by a 4,400 horsepower diesel engine (General Electric, 2008) and each railcar has a 91-tonne (100-ton) coal capacity (NETL, 2010b).

The major operation included in the transport of coal is the combustion of diesel by the locomotive engine. Loss of coal during transport is assumed to be equal to the fugitive coal dust emissions; loss during loading at the mine is assumed to be negligible as is loss during unloading. Emissions are due to diesel combustion and fugitive coal dust.

It is assumed that the majority of the railway connecting the coal mine and the CBTL facility is existing infrastructure. An assumed 25-mile rail spur is constructed between the CBTL facility and the primary railway. Table 47 lists key assumptions made in modeling rail transport of Illinois No. 6 coal.

Table 47. Key Assumptions for Rail Transport of Illinois No. 6 Coal

Primary Subject	Assumption	Basis	Source
Coal transport distance (one way)	200 miles	Estimated distance between mine exit and CBTL facility	NETL 2010a
Return trip distance	200 miles	Railcars are unloaded and returned empty to mine	Study Value
Length of rail spur to coal mine	25 miles	Feasible distance between mine site and existing railway	Study Value
Number of locomotives per unit train	5 locomotives	Industry Trend	Workgroup Engineering Judgment
Number of railcars per unit train	100 railcars	Feasible load for five 4,400 horsepower locomotives	Workgroup Engineering Judgment

5.1.1.1 Life Cycle Inventory Model

Table 48 and Figure 24 identify the individual processes modeled for Illinois No. 6 coal transport. Construction processes for the locomotive and railcars are modeled using vendor data and specifications for representative pieces of equipment. Railcar construction information is based on railcars designed for the transport of coal. Transport operations quantify the amount of diesel required/combusted in support of train travel, as well as quantifiable losses of coal during transit (e.g., fugitive dust losses, at 1.22×10^{-7} kg coal dust lost per kg-km of coal transported).

Table 48. Stage #2a First and Second Order Unit Process Names

First Order/ Assembly Process Name	Second Order Unit Process Name
Coal Unit Train, 5 Locomotives and 100 Railcars, Construction	Diesel Locomotive, 4,400 Horsepower
	Coal Railcar, 244,000 lbs Net Capacity
	Coal Unit Train Assembly, 100 Railcars
Coal Unit Train, Operation	N/A

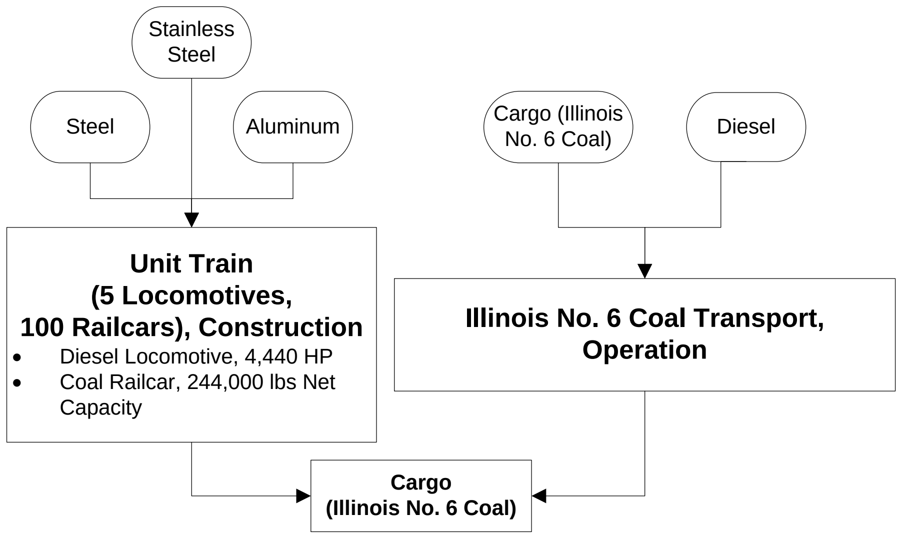


Figure 24. Process for Rail Transport of Illinois No. 6 Coal

LC Stage #2a is implemented in the LCI spreadsheet model through a number of sheets. For operations, all the input flows, output flows and GHG emissions are determined in sheet S1a.UP.O.CoalRailOp of the F-T Jet Fuel Spreadsheet Model. The input flows are:

- diesel fuel
- coal loaded onto unit train

The output flows are:

- coal delivered to CBTL facility (reference flow)
- coal lost to fugitive emissions (fugitive dust emissions)

The GHG emissions are CO_2 from non-biogenic sources, CO_2 from biogenic sources (zero for this stage), CH_4, and N_2O.

The sheet includes the following additional flows to facilitate mass balance calculations for GHGs: "CO_2 to air from combustion," "CH_4 to air from combustion," and "N_2O to air from combustion." These flows, which result from the use of diesel fuel during operation of the unit train, are used to generate the total CO_2, CH_4, and N_2O emitted to the atmosphere for operation activities in this stage.

All of these flows are calculated with equations that have adjustable parameters or variables. A number of these variables are specified as random variables with an associated probability distribution. Thus, all the flows are random variables. The equations used to calculate the

various flows are presented in detail in sheet S1a.UP.O.CoalRailOp within the F-T Jet Fuel Spreadsheet Model. The variables specified as random variables are presented in the next section.

For construction, all the input flows, output flows and GHG emissions are determined in sheet S1a.UP.C.CoalRailCon. This sheet, in turn, references information in two construction sheets: S2a.UP.C.Train and S2a.UP.C.Track. The input flows for construction in this stage are:

- steel plate, BF (85% Recovery Rate)
- steel, 316 2B (80% recycled)
- aluminum sheet
- steel, hot rolled
- diesel fuel
- wood, tie
- gravel, granite

The only output flow for construction is a constructed rail and unit train.

The GHG emissions are CO_2 from non-biogenic sources, CO_2 from biogenic sources (zero for this stage), CH_4, and N_2O.

The sheet includes the following additional flows to facilitate mass balance calculations for GHGs: "CO_2 to air from combustion," "CH_4 to air from combustion," and "N_2O to air from combustion." These flows, which result from the use of diesel fuel during installation and de-installation of the railroad track segment, are used to generate the total CO_2, CH_4, and N_2O emitted to the atmosphere for construction activities in this stage.

All of the input flows are specified as random variables with an associated distribution. The GHG emissions result from the combustion of diesel fuel. Since these two flows are random variables, the GHG emissions are also random variables. The equations used to calculate the GHG emissions are presented in detail in sheet S1a.UP.C.CoalRailCon within the F-T Jet Fuel Spreadsheet Model. The variables specified as random variables are presented in the next section.

5.1.1.2 Key Modeling Variables

The key variables with respect to the emissions of GHGs during the transport of coal by rail from the underground coal mine to the CBTL are presented in Table 49. For each variable the best estimate is presented, along with the minimum value, maximum value, most likely value, and the distribution assumed for the variable.

For many of the variables in Table 49, data were not readily available to estimate minimum, maximum, and most likely values. For example, the amount of diesel necessary to transport a kilogram of coal one kilometer is not known precisely. The best estimate in Table 49 is based on data from the US Department of Transportation's Bureau of Transportation Statistics. To determine the impact that uncertainty in this value might have on the resulting GHG emissions, it was assumed that the best estimate might be higher or lower by 10 percent. This same approach was used for a number of other uncertain variables, such as the Factor for Fugitive Emissions, and Diesel Fuel Used per Mile of Installed Railroad Track. Similarly, for all the materials used

to manufacture rail locomotives and rail cars and build the connecting railroad track (i.e., the variables Steel Plate through Gravel in Table 49), it was assumed that the best estimate might be higher or lower by 10 percent. For all these variables, it was assumed the uncertainty can be characterized by a uniform distribution. In this case, the most likely value is set at the average, although, technically, any value between the minimum and maximum of a uniform distribution is equally likely.

The One-way Distance from the Mine in Galatia to the CBTL facility is uncertain since the location of the CBTL facility is hypothetical. The best estimate of 200 miles is based on the distance from Galatia to north central/northwestern Missouri. It was assumed this distance could be high or low by 50 miles. The amount of coal produced in a given year is uncertain and depends on the capacity of the mine operations, the fraction of the capacity that is actually used, and the fraction of run-of-mine coal that is useable or marketable coal. For example, in 2005 the capacity of the Galatia mine in southern Illinois was 2,400 tonnes/hr of run-of-mine coal. The values for the variables Fraction of Capacity that is Actually Used and fraction of Run-of-Mine Coal that is Usable Coal are based on data for the Galatia mine from 2005 to 2007 to represent the average underground mine in southern Illinois.

The Length of a Railroad Segment connecting the CBTL to the main railroad is uncertain since the location of the CBTL is hypothetical. The best estimate of 25 miles is an assumption and it is further assumed that this distance could be high or low by 10 miles. It is likely that individuals determining the location of an actual CBTL facility would consider the distance to the nearest railroad tracks in this decision. A distance exceeding 35 miles seems unlikely. No information could be found on the resources required to close or de-install or decommission a railroad track. For this evaluation, it was assumed that a reasonable estimate for the resources (and emissions) needed for de-installation is 10 percent of the resources (and emissions) for installation of the track. To characterize the uncertainty in this variable, it was assumed that the resource required for de-installation could be as low as 5 percent of the resources for installation or as high as 25 percent of the resources for installation. A triangular distribution was used to characterize this uncertainty.

Table 49. Key Modeling Variables for Transport of Coal by Rail (LC Stage #2a)

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-Coal Rail Transport, Operation							
One-way Distance from Mine to CBTL Facility	mi	200	150	250	200	Uniform	Based on reasonable estimates of minimum and maximum distances from mine in southern Illinois to CBTL facility in north central to northwestern Missouri
Diesel Fuel Used per kg of Coal per km Transported	kg diesel/kg-km	5.21E-06	4.69E-06	5.73E-06	5.21E-06	Uniform	Assumes that diesel use is -10% to +10% of best estimate
Factor for Fugitive Emissions of Coal During Transport	kg/kg-km	1.20E-07	1.08E-07	1.80E-07	1.44E-07	Uniform	Assumes that fugitive dust emission factor is -10% to +50% of best estimate
Input Parameters-Coal Rail Transport, Construction							
Length of Railroad Segment from CBTL Facility to Main Railroad Line	mi	25	15	35	25	Uniform	Assumes connecting segment may need to be 10 miles shorter or longer than best estimate
Diesel Fuel Used per Mile of Installed Railroad Track	L/mi	9,200	8,280	10,120	9,200	Uniform	Assumes that diesel fuel usage factor is -10% to +10% of best estimate
Fraction of Installation Inputs and Outputs Assumed to Apply to De-Installation		0.10	0.05	0.25	0.10	Triangular	Assumed based on best engineering judgment
Steel Plate, BF (85% Recovery Rate) for a Unit Coal Train per kg Coal Delivered to CBTL Facility	kg/kg coal	4.51E-05	4.06E-05	6.76E-05	4.51E-05	Triangular	Assumes that material use is -10% to +50% of best estimate
Steel, 316 2B (80% Recycled) for a Unit Coal Train per kg Coal Delivered to CBTL Facility	kg/kg coal	3.95E-06	3.55E-06	5.92E-06	3.95E-06	Triangular	Assumes that material use is -10% to +50% of best estimate
Aluminum Sheet for a Unit Coal Train per kg Coal Delivered to CBTL Facility	kg/kg coal	4.36E-05	3.92E-05	6.54E-05	4.36E-05	Triangular	Assumes that material use is -10% to +50% of best estimate

Table 49. Key Modeling Variables for Transport of Coal by Rail (LC Stage #2a) *(Cont'd)*

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-Coal Rail Transport, Construction (Cont'd)							
Steel, Hot Rolled for Railroad Track Segment per kg Coal Delivered to CBTL Facility	kg/kg coal	4.42E-05	3.98E-05	6.63E-05	4.42E-05	Triangular	Assumes that material use is -10% to +50% of best estimate
Wood, Tie for Railroad Track Segment per kg Coal Delivered to CBTL Facility	kg/kg coal	4.43E-05	3.99E-05	6.64E-05	4.43E-05	Triangular	Assumes that material use is -10% to +50% of best estimate
Gravel, Granite for Railroad Track Segment per kg Coal Delivered to CBTL Facility	kg/kg coal	5.00E-04	4.50E-04	7.50E-04	5.00E-04	Triangular	Assumes that material use is -10% to +50% of best estimate

5.1.2 Data Quality Assessment

The results of unit process data quality evaluation for LC Stage #2a are provided in Table 50. Data quality indicators and life cycle significance determinations are listed for each unit process included in the model of this stage.

Analysis of the life cycle uncertainty significance of processes shows that the composite construction process for train transport of coal (second row of the table below), and thus all subprocesses, are below the significance threshold for the jet fuel production life cycle.

At 1.01 percent of life cycle GHG emissions, the coal unit train operation process is slightly above the significance threshold. This result determines that DQI scores below the quality requirement of 2 are flagged as data limitations. Data used for the capacity of coal railcars is of low source reliability. These data are integral to the calculation of round-trip diesel consumption of the locomotive. Low geographic representativeness was determined for fugitive dust emissions from coal transport. Reported coal loss from fugitive dust during transport was taken from an environmental evaluation of Australian coal trains. This is noted as a data limitation, but because coal loss from transport is small in comparison to coal delivered, and because Australian and US transport conventions are considered very similar, this parameter is not included in sensitivity analysis.

Table 50. Coal Transport (LC Stage #2a) Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Life Cycle Significance of Process (%)
1	Coal Unit Train, Operation	3,2,2,3,2	1.01%
1	Coal Transport, Construction	3,2,3,3,3	0.02%

5.1.3 Results

The deterministic results for Stage #2a are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S2a.Summ, which presents the input flows, output flows (products and co-products) and GHG emissions for this stage. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the functional unit. The operations unit process references are in sheet S2a.UP.O.CoalRailOp and the construction unit process references are in sheet S2a.UP.C.CoalRailCon. The GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are also presented in this sheet.

This section presents the life cycle GHG emissions for LC Stage #2a. The first section presents the deterministic results, where deterministic means the point values generated when key variables are set to their best estimates (see Table 49 for a list of key variables and their best estimates). The second section presents the range in GHG emissions when variables that are uncertain are allowed to be varied in a probabilistic simulation. The third section presents the influence of each uncertain variable on GHG emissions when the uncertain variables are systematically varied in a sensitivity analysis.

5.1.3.1 Deterministic Greenhouse Gas Emissions

Table 51 presents the life cycle GHG emissions for LC Stage #2a in terms of the reference flow for this stage, which is 1 kg of coal ready for delivery to the CBTL facility. This table presents the total emissions of 1) non-biogenic carbon dioxide from operation and construction, 2) biogenic carbon dioxide from operation and construction, 3) methane from operation and construction, 4) nitrous oxide from operation and construction and 5) other GHGs from operation and construction. This last category, other GHGs, captures emissions from GHGs other than carbon dioxide, methane or nitrous oxide, or emissions that are expressed in carbon dioxide equivalents and cannot be differentiated into the primary GHGs. The second column in the table presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the IPCC 2007, IPCC 2001 and IPCC 1996 estimates, respectively.

As indicated in Table 51, operation of the coal rail train contributes far more to life cycle GHG emissions than do construction of the locomotives, rail cars, and the connecting railroad tracks (including installation and de-installation of the railroad tracks). Operations account for over 98 percent of the total life cycle GHG emissions for LC Stage #2a, mostly due to emissions of carbon dioxide.

Table 51. LC Stage #2a GHG Emissions (per kg Coal Delivered to CBTL Facility)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/kg coal)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg coal) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg coal) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg coal) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	13.0	13.0	13.0	13.0
Non-biogenic CO_2 – Construction	0.2	0.2	0.2	0.2
Non-biogenic CO_2 – Subtotal	13.0	13.0	13.0	13.0
Biogenic CO_2 – Operation	0.0	0.0	0.0	0.0
Biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Biogenic CO_2 – Subtotal	0.0	0.0	0.0	0.0
CH_4 – Operation	0.01	0.4	0.3	0.3
CH_4 – Construction	0.00	0.0	0.0	0.0
CH_4 – Subtotal	0.02	0.4	0.3	0.3
N_2O – Operation	0.000	0.1	0.1	0.1
N_2O – Construction	0.000	0.0	0.0	0.0
N_2O – Subtotal	0.000	0.1	0.1	0.1
Other GHG – Operation		0.0	0.0	0.0
Other GHG – Construction		0.0	0.0	0.0
Other GHG – Subtotal		0.0	0.0	0.0
Operation – Total		14.0	13.0	13.0
Construction– Total		0.2	0.2	0.2
Grand Total		14.0	13.0	13.0

Note: Subtotals and totals may not sum exactly due to rounding.

5.1.3.2

In an attempt to quantify the influence of uncertainty in the key variables (discussed previously) on the calculated GHG emissions, probabilistic simulations were performed. The model for calculating life cycle GHG emissions has a number of variables that are considered uncertain (see Table 49).

In this evaluation, probabilistic simulations were performed for total life cycle GHG emissions using the IPCC 2007 global warming potentials. CO_2 equivalent emissions were calculated relative to the stage reference flow of 1 kg coal ready for delivery to the CBTL facility. The CO_2e emissions relative to the reference flow range from 9.4 to 19 g CO_2e/kg coal, with a median value of 14 g CO_2e/kg coal, a mean of 14 g CO_2e/kg coal, and a standard deviation of 2.1 g CO_2e/kg coal. Eighty percent of the distribution lies between 11 and 16 g CO_2e/kg coal, and the middle fifty percent of the distribution lies between 12 and 15 g CO_2e/kg coal.

Table 52 presents the statistics for the CO_2e emissions developed from the simulations. Figure 25 presents the cumulative distribution and probability density function for CO_2 equivalent emissions relative to the LC Stage #2a reference flow. In Figure 25, the vertical scale on the left is for the probability density function and the vertical scale on the right is for the cumulative distribution.

The CO_2 equivalent emissions relative to the reference flow range from 9.4 to 19 g CO_2e/kg coal, with a median value of 14 g CO_2e/kg coal, a mean of 14 g CO_2e/kg coal, and a standard deviation of 2.1 g CO_2e/kg coal. Eighty percent of the distribution lies between 11 and 16 g CO_2e/kg coal, and the middle fifty percent of the distribution lies between 12 and 15 g CO_2e/kg coal.

Table 52. LC Stage #2a Probabilistic Uncertainty Analysis; Statistics for CO_2e Emissions

Statistical Parameter	Mass of GHG Emitted to Atmosphere (g CO_2e/kg coal) (IPCC 2007 GWP)
Minimum	9.4
10%	11
25%	12
Median (50%)	14
75%	15
90%	16
Maximum	19
Mean	14
Mode	14
Stand. Deviation	2

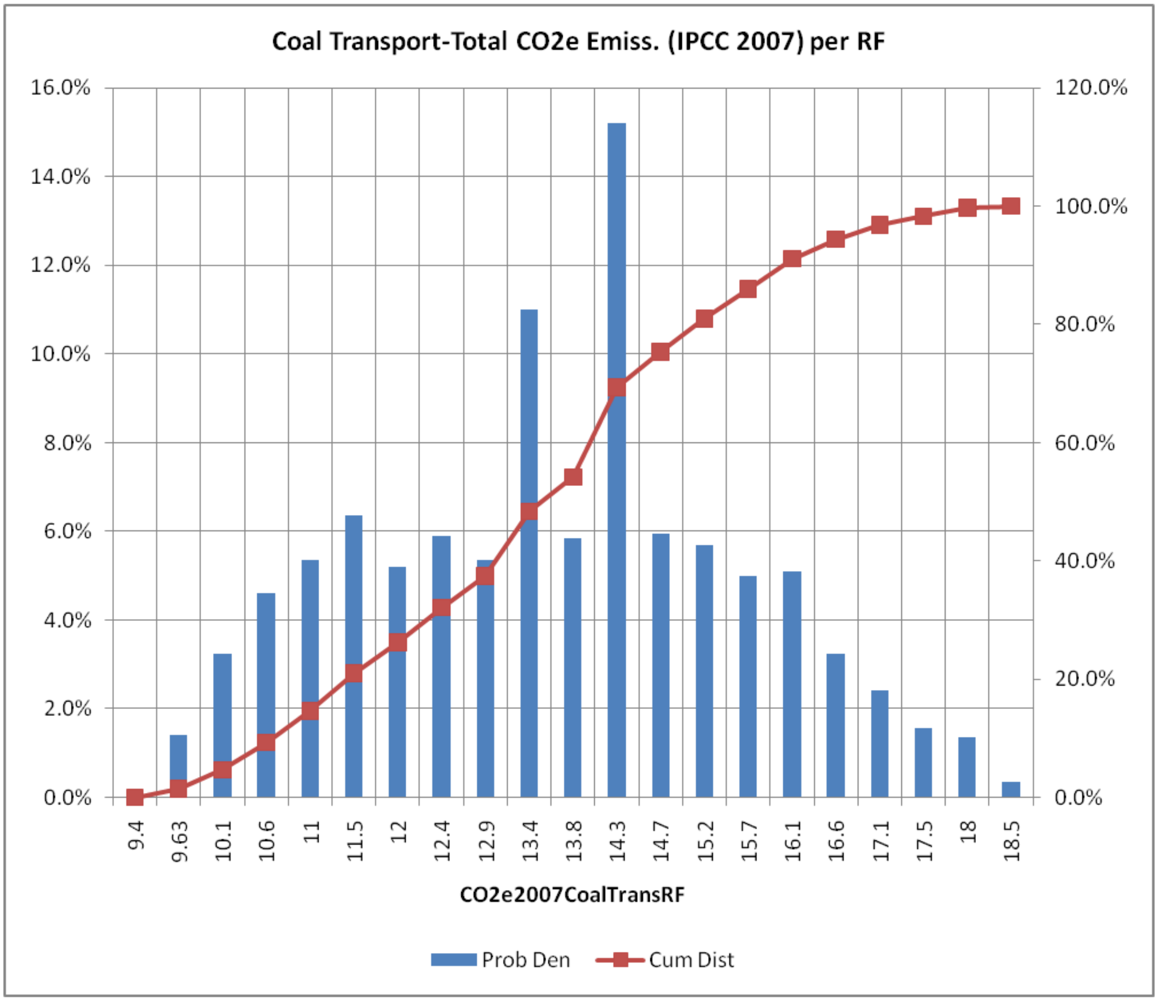


Figure 25. LC Stage #2a Probability Density Function and Cumulative Distribution of CO_2e Emissions (Using IPCC 2007 GWP) (per kg Coal Delivered to CBTL Facility)

5.1.3.3 Sensitivity Analysis

In the sensitivity analysis, the total CO_2e emission using the IPCC 2007 global warming potentials was calculated for each key variable. Table 53 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions. The Absolute Difference for each key variable is also shown, and key variables are listed from highest to lowest based on their Absolute Difference. This same result is presented graphically in the tornado chart presented in Figure 26.

The variable that has the most influence is the "One-way Distance from the Mine to the CBTL," followed by the "Diesel Fuel Used to transport 1 kg of coal 1 km." All other key variables have very small Absolute Differences, implying that these variables have a negligible influence on total CO_2e emissions. The tornado chart clearly indicates that the "One-way Distance from the Mine to the CBTL" and the "Diesel Fuel Used to transport 1 kg of coal 1 km" are the most influential of the key variables; other variables are shown, but are very small in comparison to these two key variables. That the key variables associated with construction (e.g., all the

variables associated with mass of materials needed to manufacture coal mining equipment or install a coal mine) have little influence on the CO_2e emissions is consistent with the deterministic results, which indicate that construction emissions are responsible for less than 2 percent of the total CO_2e emissions.

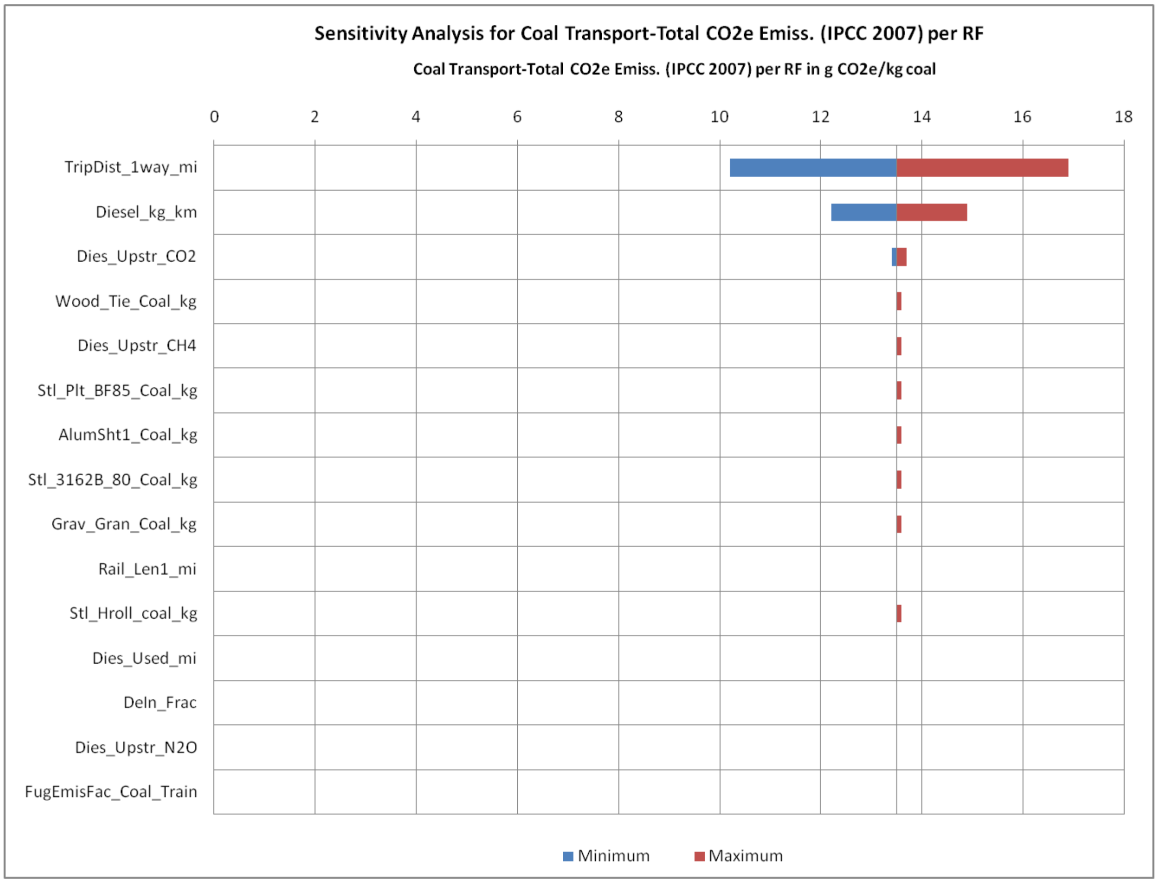


Figure 26. LC Stage #2a Sensitivity Analysis Results (Using IPCC 2007 GWP) (g CO_2e per kg Coal Delivered to CBTL Facility)

Table 53. Sensitivity Analysis Results (Using IPCC 2007 GWP) (g CO_2e/kg Coal Delivered to CBTL Facility)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/kg coal)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi	mi	200	150	250	10.2	16.9	6.67
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	12.2	14.9	2.67
Upstream CO_2 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CO2	kg CO_2/kg	0.718	0.683	0.754	13.4	13.7	0.241
Wood, Tie for Railroad Track Segment per kg Coal Delivered to CBTL	Wood_Tie_Coal_kg	kg/kg coal	0.0000497	0.0000447	0.0000745	13.5	13.6	0.0433
Upstream CH_4 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CH4	kg CH_4/kg	0.004	0.0038	0.0042	13.5	13.6	0.0335
Steel Plate, BF (85% Recovery Rate) for a Unit Coal Train per kg Coal Delivered to CBTL	Stl_Plt_BF85_Coal_kg	kg/kg coal	0.0000451	0.0000406	0.0000676	13.5	13.6	0.0324
Aluminum Sheet for a Unit Coal Train per kg Coal Delivered to CBTL	AlumSht1_Coal_kg	kg/kg coal	0.0000436	0.0000392	0.0000654	13.5	13.6	0.0192
Steel, 316 2B (80% Recycled) for a Unit Coal Train per kg Coal Delivered to CBTL	Stl_3162B_80_Coal_kg	kg/kg coal	0.00000395	0.00000355	0.00000592	13.5	13.6	0.0128
Gravel, Granite for Railroad Track Segment per kg Coal Delivered to CBTL	Grav_Gran_Coal_kg	kg/kg coal	0.000561	0.000505	0.000841	13.5	13.6	0.00794
Length of Railroad Segment from CBTL Facility to Main Railroad Line	Rail_Len1_mi	mi	25	15	35	13.5	13.5	0.00606
Steel, Hot Rolled for Railroad Track Segment per kg Coal Delivered to CBTL	Stl_Hroll_coal_kg	kg/kg coal	0.0000495	0.0000446	0.0000743	13.5	13.6	0.00575
Diesel Fuel Used per Mile of Installed Railroad Track	Dies_Used_mi	L/mi	9200	8280	10100	13.5	13.5	0.00152
Fraction of Installation Inputs and Outputs Assumed to Apply to De-Installation	DeIn_Frac		0.1	0.05	0.25	13.5	13.5	0.00138
Upstream N_2O Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_N2O	kg N_2O/kg	0.000013	0.0000123	0.0000136	13.5	13.5	0.0013

5.2 Switchgrass Transport (LC Stage #2b)

LC Stage #2b represents the transport of switchgrass produced under LC Stage #1b from bale storage to the CBTL facility under LC Stage #3a. Transport is accomplished via semi trucks. Diesel combustion emissions associated with the operation of the trucks is the primary source of operational emissions accounted for under this LC Stage.

Although construction of the transport trucks is accounted for under this LC Stage, no roadways or other ancillary facilities are included. Based on the land use assessment performed by EneGis (2010), switchgrass is assumed to be transported an average distance of 40 km from storage to the CBTL facility.

5.2.1 Modeling Approach and Data Sources

Harvested switchgrass is transported by semi truck from the agricultural production facilities located in northern Missouri/southern Iowa (the Chariton Valley) to the CBTL facility in north central or north western Missouri, a distance of 40 km (round trip distance of 80 km). Semi trucks transport switchgrass stored as rectangular bales or round bales depending on the method of biomass storage selected under LC Stage #1b. All roadways that would be used in support of switchgrass transport are assumed to be pre-existing.

Bales are assumed to have between a 10 percent and 20 percent moisture content at haul, with 15 percent used as the best estimate. Bales are assumed to be loaded and unloaded using 75HP tractor and 55HP tractor and loader. Transport is by trucks assumed to operate at 2.1 kpl (5 mpg) for both the front haul and the return trip at a load of 20 tons irrespective of the bale type. Because the 20 tons of material would be transported regardless of switchgrass packing volume, the amount of fuel required to haul switchgrass does not depend on the type bale (rectangular or round) that is transported. Also, no losses were assumed during transport operations. Table 54 lists key assumptions made in modeling truck transport of switchgrass.

Table 54. Key Assumptions for Truck Transport of Switchgrass

Primary Subject	Assumption	Basis	Source
Switchgrass transport distance	40 km	Estimated distance between switchgrass production and the CBTL facility	EneGis (2010)
Return trip distance	40 km	Semi trucks are unloaded and returned empty to mine	EneGis (2010)
Amount of switchgrass hauled per truck	20 tons	Estimated semi-truck capacity	Workgroup Engineering Judgment

Airborne emissions produced under this LC Stage during operations result from the combustion of diesel by transport trucks. Equipment requirements, fuel and lubricant use, and related emissions are estimated on the basis of the operating time for the tractors and loader as provided by Bransby et al. (Bransby, 2005) and on the basis of operating fuel efficiency for the transport itself (assuming 2.1 kpl [5 mpg]). Finally, lubricant use estimated as 10 percent of total fuel use.

Resource use and emissions for the primary switchgrass transport processes are presented in Table 55 through Table 57 to provide 1.4 million *dry* tonnes switchgrass/year (3,855 dry tonnes switchgrass/day) to the CBTL facility.

Table 55. Switchgrass Transport: Fuel and Lubricant

Petroleum Product	Units	Best Estimate Value	Range (Best to Worst Case)
Diesel Fuel	liters/year	1.5E+07	1.3E+07 to 1.6E+07
Lubricant	liters/year	1.5E+06	1.3E+06 to 1.6E+06

Table 56. Switchgrass Transport: Equipment

Petroleum Product	Units	Best Estimate Value	Range (Best to Worst Case)
Tractor and loader, 55HP	units	51	46 to 56
Tractor, 75HP	units	72	65 to 79
Truck, flatbed semi	units	68	61 to 74

Table 57. Switchgrass Transport: GHG Emissions

Petroleum Product	Units	Best Estimate Value	Range (Best to Worst Case)
Carbon dioxide (CO_2): non-biogenic, to air	kg/year	3.7E+07	3.4E+07 to 3.9E+07
Methane (CH_4): non-biogenic, to air	kg	390	340 to 430
Nitrous oxide (N_2O): non-biogenic, to air	kg	550	470 to 600

Documentation and datasheets of all secondary developed assembly processes and unit processes modeled within LC Stage #2b were incorporated into this model based on data and unit processes previously compiled by NETL. These sheets contain information on all source data, calculations and conversions performed, and relevant assumptions made for modeling of individual processes. The names of these processes and documentation sheets are provided in Table 58 for reference.

Table 58. Switchgrass Transport: First and Second Order Unit Processes

First Order Unit Process	Second Order Unit Process: Consumables	Second Order Unit Process: Equipment Construction
Switchgrass Transport	Diesel	Tractor and Loader, 55 HP
	Lubricant	Tractor, 75 HP
		Truck, Flatbed Semi

5.2.2 Data Quality Assessment

The results of unit process data quality evaluation for LC Stage #2b are provided in Table 59. Data quality indicators and life cycle significance determinations are listed for each unit process included in the model of this stage.

Analysis of the life cycle uncertainty significance of processes shows that the composite construction process for switchgrass transport construction processes are below the significance threshold for the jet fuel production life cycle. The operation process for switchgrass transport is of sufficient data quality to preclude sensitivity analysis.

Table 59. Switchgrass Transport (LC Stage #2b) Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Life Cycle Significance of Process (%)
1	Switchgrass Transport, Operation	3,2,1,1,1	0.40%
1	Switchgrass Transport, Construction	3,2,1,1,1	0.06%

5.2.3 Results

This section presents the life cycle GHG emissions for LC Stage #2b. The first part of this section presents the deterministic results for transporting baled switchgrass by tractor trailer to the CBTL facility. In the deterministic analysis, each uncertain variable was set to its most likely value based on engineering judgment. Given the data quality score of 3 in the "Source Reliability" category and according to the Framework and Guidance Document, the unit process data are categorized as of low quality and have been varied to the minimum and maximum values estimated as described above.

As discussed for LC Stage #1b, the model for this stage was implemented in Excel in a way that allows a systematic uncertainty analysis and sensitivity analysis of critical variables that influence outputs could not be performed. However, a number of the input flows in the model for this stage are uncertain and a separate analysis established minimum and maximum values for input flows and direct GHG emissions. The input flows generate GHG emissions through secondary emissions and allowing the input flows to vary allows the secondary emissions to vary. Similarly, allowing the direct emission of GHGs to vary directly influences the resulting CO_{2e} emissions. The second part of this section presents the range in GHG emissions when input flows and direct emissions are allowed to be varied in a probabilistic simulation. The third part of this section presents a sensitivity analysis for the GHG emissions from these uncertain variables.

5.2.3.1 Deterministic Greenhouse Gas Emissions

The deterministic results for LC Stage #2b are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S2b.Summ, which presents the input flows, output flows (products and co-products) and GHG emissions for this stage. The sheet is organized with flows in rows and unit processes in columns. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the functional unit. The operations unit process references are in sheet S2b.UP.O.BioTranOp and the construction unit process references are in sheet S2b.UP.C.BioTranCon. Secondary unit process references are in sheet Sec.UP.All. At the stage and system level, total flows are calculated for operations, construction, and the sum of operations and construction. GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are also presented in this sheet.

Table 60 presents the life cycle GHG emissions for LC Stage #2b in terms of the reference flow for this stage, which is 1 tonne of switchgrass delivered to the CBTL facility. This table presents the total emissions of 1) non-biogenic carbon dioxide from operation and construction, 2) biogenic carbon dioxide from operation and construction, 3) methane from operation and construction, 4) nitrous oxide from operation and construction, and 5) other GHGs from operation and construction. This last category, other GHGs, captures emissions from GHGs

other than carbon dioxide, methane, or nitrous oxide, or emissions that are expressed in carbon dioxide equivalents and cannot be differentiated into the primary GHGs. The second column in the table presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the IPCC 2007, IPCC 2001, and IPCC 1996 estimates, respectively.

As indicated in Table 60, CO_2 is responsible for over 97 percent of the total CO_2e GHG emissions. Operational activities are responsible for about 87 percent of the total, with construction making up the remainder. The GHG emissions are essentially the same for the three different methods of baling and storing the switchgrass (rectangular bales, covered; round bales, covered; and round bales, uncovered). Table 60 presents the results for rectangular bales, but the total CO_2e GHG emissions for the other two methods of baling and storing switchgrass are the same.

5.2.3.2 Probabilistic Uncertainty Analysis

A probabilistic uncertainty analysis was included, because data quality were low for switchgrass transport operations, and because switchgrass transport operations represent over 0.1 percent of the total LC emissions for the study (see DQI analysis). As discussed above, a separate analysis provided ranges for input flows and direct emissions of GHGs. The input flows that had the most influence on total non-biogenic CO_2e emissions for this stage are presented in Table 61, which presents the minimum and maximum values for these input flows as well as the minimum and maximum values for the direct emissions of non-biogenic CO_2, CH_4, and N_2O. All the variables in Table 61 are assumed to follow a triangular distribution.

To quantify the influence on the calculated GHG emissions of uncertainty in the variables presented in Table 61, probabilistic simulations were performed. In this evaluation, probabilistic simulations were performed for the total CO_2 equivalent emissions using the IPCC 2007 global warming potentials relative to the stage reference flow of 1 tonne of switchgrass delivered to the CBTL facility. Table 62 presents the statistics for the CO_2e emissions developed from the simulations. Figure 27 presents the cumulative distribution and probability density function for CO_2 equivalent emissions relative to the LC Stage #2b reference flow. In Figure 27, the vertical scale on the left is for the probability density function and the vertical scale on the right is for the cumulative distribution.

Table 60. LC Stage #2b GHG Emissions for Transport of Switchgrass to the CBTL Facility (per Dry Tonne of Switchgrass Delivered to the CBTL Facility)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/tonne Switchgrass)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne Switchgrass) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne Switchgrass) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne Switchgrass) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	33,000	33,000	33,000	33,000
Non-biogenic CO_2 – Construction	4,300	4,300	4,300	4,300
Non-biogenic CO_2 – Subtotal	37,000	37,000	37,000	37,000
Biogenic CO_2 – Operation	0	0	0	0
Biogenic CO_2 – Construction	0	0	0	0
Biogenic CO_2 – Subtotal	0	0	0	0
CH_4 – Operation	36	900	820	750
CH_4 – Construction	12	300	280	260
CH_4 – Subtotal	48	1,200	1,100	1,000
N_2O – Operation	0.50	150	150	160
N_2O – Construction	0.18	54	54	57
N_2O – Subtotal	0.69	200	200	210
Other GHG – Operation		0	0	0
Other GHG – Construction		0	0	0
Other GHG – Subtotal		0	0	0
Operation – Total		34,000	34,000	34,000
Construction– Total		4,700	4,600	4,600
Grand Total		39,000	39,000	39,000

Note: Subtotals and totals may not sum exactly due to rounding.

The total CO_2 equivalent emissions relative to the reference flow range from 36 to 40 kg CO_2e/tonne switchgrass, with a median value of 38 kg CO_2e/tonne switchgrass, a mean of 38 kg CO_2e/tonne switchgrass, and a standard deviation of 0.74 kg CO_2e/tonne switchgrass. Eighty percent of the distribution lies between 37 and 39 kg CO_2e/tonne switchgrass, and the middle fifty percent of the distribution lies between 38 and 39 kg CO_2e/tonne switchgrass, at least to two significant figures.

Table 61. Uncertainty in Key Input Flows and Direct Emissions for Switchgrass Transport (LC Stage #2b)

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters and Direct Emissions for-Switchgrass Transport, Operation							
Carbon dioxide (CO_2): non-biogenic, to air	kg/tonne	26.3	24.3	27.7	26.3	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Methane (CH_4): to air	kg/tonne	2.79E-04	2.38E-04	3.07E-04	2.79E-04	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Nitrous oxide (N_2O): total to air	kg/tonne	3.89E-04	3.36E-04	4.24E-04	3.89E-04	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Diesel fuel	kg/tonne	8.75E+00	8.00E+00	9.25E+00	8.75E+00	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Input Parameters-Switchgrass Transport, Construction							
Tractor and loader, 55HP	pcs/tonne	3.61E-05	3.25E-05	3.97E-05	3.61E-05	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Tractor, 75HP	pcs/tonne	5.12E-05	4.61E-05	5.63E-05	5.12E-05	Triangular	Minimum, maximum, and best estimate determined in separate analysis.
Truck, flatbed semi	pcs/tonne	4.81E-05	4.33E-05	5.29E-05	4.81E-05	Triangular	Minimum, maximum, and best estimate determined in separate analysis.

Table 62. LC Stage #2b: Probabilistic Uncertainty Analysis; Statistics for Total CO_2e Emissions

Statistical Parameter	Mass of GHG Emitted to Atmosphere (kg CO_2e/tonne switchgrass) (IPCC 2007 GWP)
Minimum	36
10%	37
25%	38
Median (50%)	38
75%	39
90%	39
Maximum	40
Mean	38
Mode	38
Stand. Deviation	7.7

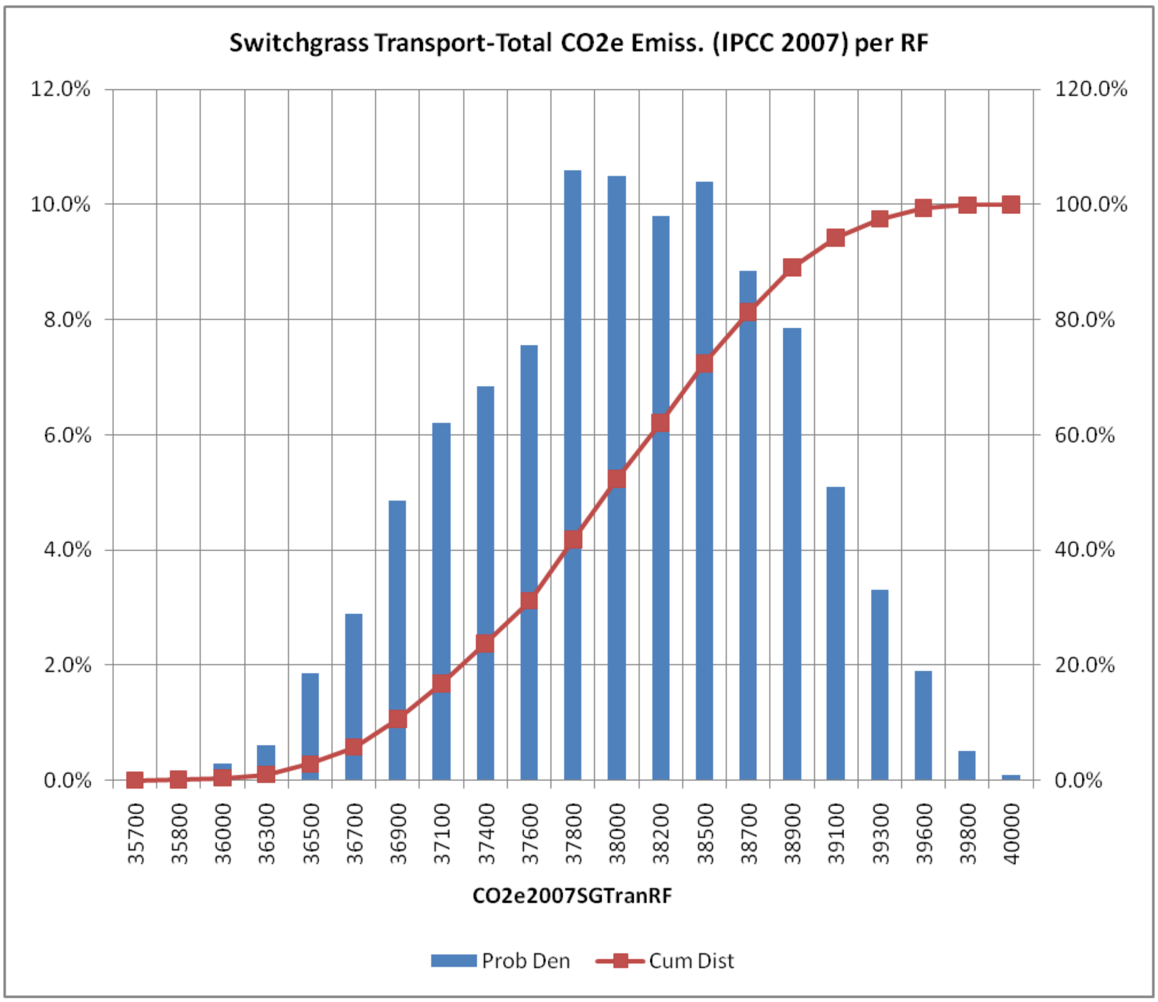


Figure 27. LC Stage #2b Probability Density Function and Cumulative Distribution of CO_2e Emissions (Using IPCC 2007 GWP) (g CO_2e/Dry Tonne Switchgrass Delivered to CBTL Facility)

5.2.3.3 Sensitivity Analysis

In the sensitivity analysis, the total non-biogenic CO_2e emission using the IPCC 2007 global warming potentials was calculated for each key variable in Table 61. Table 63 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions. The Absolute Difference for each key variable is also shown, and key variables are listed from highest to lowest based on their Absolute Difference. This same result is presented graphically in the tornado chart presented in Figure 28.

The variable that has the most influence is the direct emissions of CO_2 during the transport of switchgrass. The next two most important variables, diesel fuel and materials for the flatbed semi-truck, are important for their secondary emissions of GHGs (i.e., the emissions of GHGs in their production). All other key variables have a negligible influence on total CO_2e emissions.

Table 63. Sensitivity Analysis Results for Total CO_2e Emissions for Stage #2b (Using IPCC 2007 GWP) (g CO_2e/Dry Tonne Switchgrass Delivered to CBTL Facility)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/tonne switchgrass)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x	kg/tonne	26.3	24.3	27.7	36300	39700	3420
Diesel fuel	Diesel_x	kg/tonne	8.75	8	9.25	37700	38800	1030
Upstream CO_2 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CO2	kg CO_2/kg	0.718	0.683	0.754	38000	38700	628
Truck, flatbed semi	TruckFlatBed1_x	pcs/tonne	0.0000481	0.0000433	0.0000529	38100	38600	570
Tractor, 75HP	AgTrac_75hp_x	pcs/tonne	0.0000512	0.0000461	0.0000563	38300	38500	210
Tractor and loader, 55HP	AgTracLoad_55hp_x	pcs/tonne	0.0000361	0.0000325	0.0000397	38300	38400	148
Upstream CH_4 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CH4	kg CH_4/kg	0.004	0.0038	0.0042	38300	38400	87.4

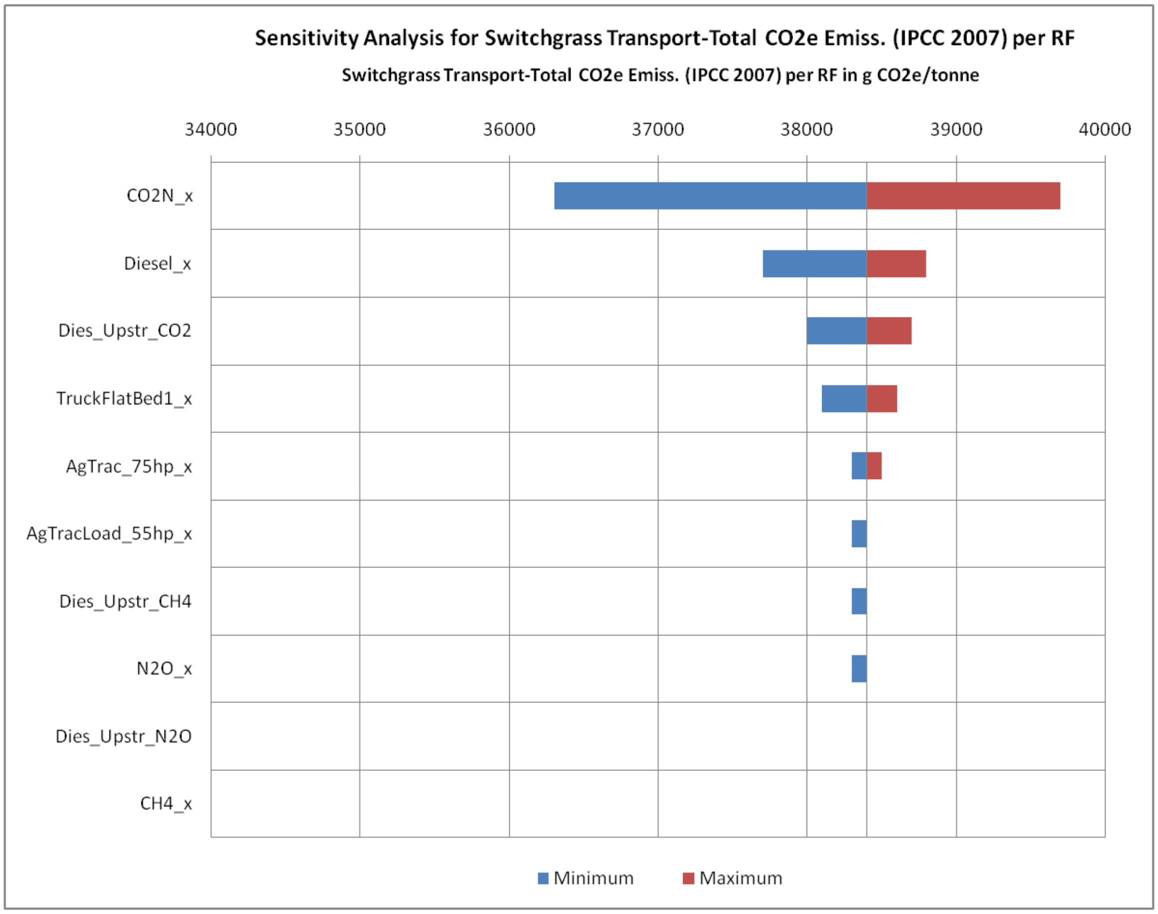


Figure 28. LC Stage #2b Sensitivity Analysis Results for Total CO_2e Emissions (Using IPCC 2007 GWP) (g CO_2e/Tonne Switchgrass Delivered to CBTL Facility)

6.0 LC STAGE #3: LIQUID FUELS PRODUCTION

LC Stage #3 incorporates liquid fuels production via the CBTL facility, as well as carbon management strategies including the use of supercritical carbon dioxide for enhanced oil recovery or the injection of supercritical carbon dioxide into a saline geologic aquifer for sequestration.

6.1 Coal and Biomass to Liquids Facility (LC Stage #3a)

LC Stage #3a starts at the gate of the CBTL facility and ends at the boundaries for LC Stage #3b, at the start of a pipeline used for the transport of carbon dioxide for enhanced oil recovery (LC Stage #3c) or saline geologic aquifer sequestration (LC Stage #3d); and for LC Stage #4, at the start of a pipeline used for the transport of fuels produced by the CBTL facility under LC Stage #4.

LC Stage #3a includes production of F-T jet fuel from five different 30,000 bbl/d CBTL facility configurations. Each of these configurations is an independent pathway for developing F-T jet fuel. The design and construction of the five CBTL facilities is tailored to each configuration. Specifically, three iron-based F-T catalyst designs using 0 percent, 16 percent, and 31 percent biomass were modeled and two cobalt-based F-T catalyst designs using 14 percent biomass with and without optimization to maximize jet fuel production (see Table 64 below). The effects of CBTL plant configurations and F-T catalyst options are reported and discussed below.

6.1.1 Modeling Approach and Data Sources

The following text provides relevant details regarding CBTL facility design, assumptions, characteristics, and data sources considered in this study.

6.1.1.1 Scenarios for the CBTL Facility

Several scenarios are included in the CBTL facility, in order to capture potential variations in feedstock input scenarios, CBTL operations, and product outputs. These scenarios are summarized in Table 64.

Table 64. CBTL Facility Scenarios

Scenario Number	Percent Switchgrass Biomass	Percent Illinois No. 6 Coal	F-T Catalyst	Notes
1	0%	100%	Iron	Coal feed only
2	16%	84%	Iron	Baseline scenario
3	31%	69%	Iron	High biomass scenario
4	14%	86%	Cobalt	Similar to baseline scenario
5	14%	86%	Cobalt	Maximize jet fuel production, minimize diesel production

6.1.1.2 Baseline Scenario for Gasification-Based Production of F-T Jet Fuel

Different feedstocks can be used in the production of F-T fuels, including natural gas, coal, and various sources of biomass such as switchgrass, wood chips, or corn stover. For this study, coal and switchgrass biomass are the primary source materials. Also, a variety of process configurations are possible for converting a coal, biomass, or a co-feed of coal and biomass to F-T liquids (termed coal-and-biomass to liquids, or *CBTL*). For this analysis, the process design (and corresponding detailed process simulation results) developed by Tarka and co-workers at

NETL form the basis for the baseline scenario (Case #7 identified in Table 2-1 of the January 2009 report by Tarka, 2009). This particular design uses a co-feed of coal and biomass, and is configured to maximize production of liquid fuels, and to produce just enough electricity, as a co-product, to meet on-site demands. The Tarka (2009) report does not present detailed mass and energy balances for Case 7, but the author provided these details by personal communication for this analysis (Tarka, 2010a).

Others have proposed plant designs that produce F-T fuels with a major exportable electricity co-product (Larson et al., 2010). The F-T fuels produced from a power/fuels co-production facility may have a different GHG footprint from the baseline scenario plant design considered here, but the overall approach to the assessment of GHG emissions would be similar to that discussed here. Table 65 provides an overview of key assumptions for LC Stage #3a.

Table 65. Key Assumptions for the F-T Jet Fuel CBTL Facility

Primary Subject	Assumption	Basis	Source
CBTL Facility Production Throughput (liquid products)	30,000 Barrels per Day	Assumed reasonable design flow capacity, based on feedstock requirements and study scope and planning	Basis for Study Design
Carbon Dioxide Management Strategy	Carbon Capture for subsequent sequestration and/or beneficial use	Available carbon dioxide management strategies to minimize GHG emissions	Basis for Study Design
Feedstocks Accepted by CBTL Facility	Switchgrass Biomass, Illinois No. 6 Coal	Feedstocks considered in study scope	Basis for Study Design
Products Generated by CBTL Facility	F-T Jet Fuel, Diesel (in some cases), Naphtha, , Carbon Dioxide	Facility design for the CBTL facility: this suite of products would result from the CBTL process	Workgroup Engineering Judgment
Fischer-Tropsch Catalyst	Iron or Cobalt	Facility design includes the use of either an iron or cobalt F-T catalyst	Basis for Study Design

6.1.1.3 CBTL Facility Design

The distinguishing features of the baseline scenario design are 1) a liquid fuels production capacity of 30,000 barrels per day, 2) a biomass input equal to 16 percent (by mass) of the combined as-received coal-plus-biomass input, 3) an iron catalyst F-T unit, and 4) capture of CO_2 for storage. Figure 29 provides a simplified block diagram for this design.

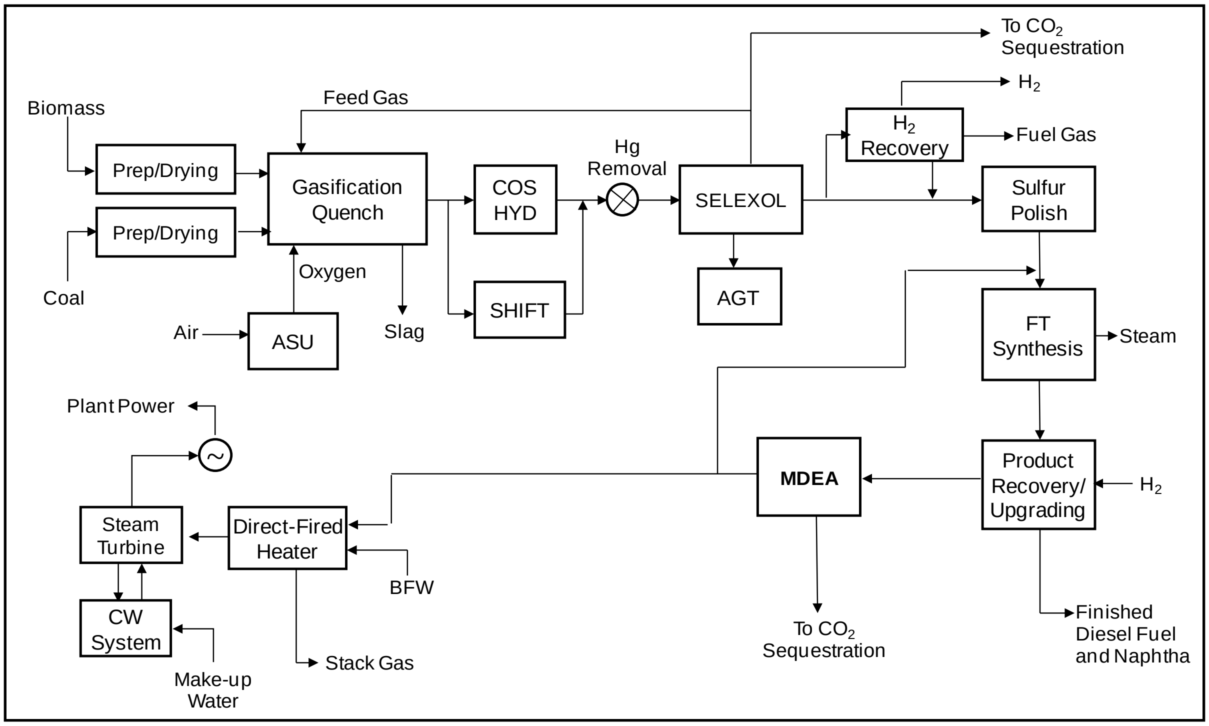


Figure 29. Simplified Process Diagram for the Baseline Scenario CBTL Facility System

6.1.1.4 CBTL Facility Operational Details

At the CBTL facility gate, bales of switchgrass (15 percent moisture by weight) arrive by truck and Illinois No. 6 sub-bituminous coal (11.11 percent moisture by weight) arrives by rail. Both feedstocks must be prepared for processing by grinding and drying. For switchgrass, a de-baler breaks up the bales into loose grass. For the iron catalyst scenarios, the loose switchgrass is then fed into a natural gas fired drier. This pre-process drier reduces the moisture content to a nominal 10 percent (by weight). Emissions from the combustion of natural gas for drier operation are accounted for within the model. These drying steps are not required for Scenarios 4 and 5, which use a cobalt catalyst, because the cobalt process is designed to use switchgrass having 15 percent moisture content (by weight).

After the initial drying stage, the biomass is then fed to the grinder to reduce its size to one millimeter or less to ensure proper feeding to the gasifier. Finally, before it is fed to the gasifier, it is dried to 5 percent moisture (by weight) using driers fired with fuel gases produced downstream at the CBTL facility. Coal is unloaded from rail cars and crushed/ground to a size distribution that is 17 percent less than 200 mesh, and also dried to 5 percent moisture (by weight).

The ground and dried feedstocks are fed with oxygen (95 percent purity) from a conventional cryogenic air separation unit (ASU) into a Shell-type entrained flow gasifier operating at 42 bar (615 psia) pressure and 1308°C (2388°F). This high-temperature entrained flow gasifier design was selected by NETL engineers because high-temperature processing can ensure that tars are completely destroyed and methane production from the gasifier is minimized. Moreover, among several entrained-flow gasifiers available commercially, the Shell-type design is the only gasifier

with any substantial commercial operating experience with co-firing biomass (at the Buggenum IGCC plant in the Netherlands). Ash leaves the gasifier as molten slag, and a direct contact water quench spray system is used to cool the exiting syngas. The quench also serves to remove entrained particulate matter and contaminants.

Syngas leaving the quench is split into two streams. One stream goes to a water gas shift (WGS) reactor, which shifts the ratio of H_2 to CO in the syngas via the WGS reaction: $CO + H_2O \leftrightarrow CO_2 + H_2$. The syngas leaving the gasifier has a H_2:CO ratio of 0.4, whereas the downstream iron catalyst F-T synthesis unit requires a value of 1 or 1.1. The impact of varied biomass usage, which affects the ratio of H_2:CO produced in the gasifier, will be examined via scenarios with 0 percent, 14 percent or 16 percent, and 31 percent of the as-received feedstock mass consisting of biomass. For the baseline scenario, the fraction of biomass is 16 percent (as-received) of the total feedstock mass (as-received). Some syngas bypasses the WGS to a carbonyl sulfide (COS) hydrolysis unit that converts COS into hydrogen sulfide (H_2S), a sulfur compound that can be readily removed from the gas stream in the downstream acid gas removal (AGR) unit. (Any COS passing through the WGS is hydrolyzed by reactions in that unit.) The two streams are then re-combined and cooled before passing through activated carbon filters to remove mercury and then to a two-stage acid gas removal system (designed using a Selexol™ physical absorption system).

The Selexol™ unit selectively removes H_2S, which would otherwise poison downstream catalysts, as well as CO_2. CO_2 is removed to enable more efficient and less capital-intensive downstream syngas conversion to liquids. The pure stream of CO_2 available from the Selexol unit can be vented to the atmosphere or, as in our baseline scenario design, dried and compressed to 150 bar (2200 psia) for pipeline transport as a supercritical fluid to an injection site for storage. The captured H_2S is fed to a Claus/SCOT system for acid gas treatment (AGT) and recovery of elemental sulfur.

The synthesis gas exiting the Selexol™ unit may still contain 1 to 2 ppmv H_2S – too high a concentration for the sulfur sensitive Fischer-Tropsch catalyst. Sulfur polishing reactors are used in which zinc oxide reacts with the H_2S to form solid zinc sulfide to reduce the H_2S concentration to less than 0.03 ppmv.

Following the AGR, hydrogen is recovered from a portion of the clean synthesis gas to be used in hydrotreating and hydrocracking in the downstream Fischer-Tropsch upgrading section. Hydrogen recovery is via membrane and pressure swing adsorption (PSA) systems.

The clean synthesis gas is finally fed to the F-T synthesis unit, where it is heated and then fed to the bottom of the slurry-bed F-T synthesis units operating at about 220^{o}C (428^{o}F). The gas bubbles up through a heavy liquid hydrocarbon in which the iron-based catalyst particles are suspended. Heat generated by the F-T reactions is efficiently removed by steam-generation inside tubes embedded in the slurry bed. Because iron-based F-T catalysts promote the WGS reaction along with the F-T reactions, the syngas is only required to have an H_2:CO molar ratio of 1:1 to 1.1:1. This is less than that of other F-T catalysts, such as cobalt, which require higher ratios of H_2:CO, as described below. The relatively low temperature of the base case F-T reactor design helps optimize production of long-chain hydrocarbons that can be selectively hydrocracked into liquid fuels, with some fuel gas production. The raw liquid products are sent to the recovery/upgrading sub-system, where hydrogen (recovered from upstream) is used in hydrocracking and hydrotreating operations, resulting in the production of F-T diesel, naphtha, and fuel gas. The liquid products are roughly 70 percent by volume F-T diesel and 30 percent by

volume F-T naphtha. Alternatively, the liquid products could be separated into F-T jet fuel, diesel, and naphtha, as described later in this section. The F-T jet fuel contains no sulfur and can be blended up to 50 percent by volume (certification requirement) with petroleum-derived fuels in order to create turbine fuel that would meet relevant military specifications. The naphtha generated by the plant is suitable as a chemical or gasoline feedstock, and the diesel can be used in any diesel engine.

The F-T reactor also produces a tail gas stream containing CO_2, unreacted H_2 and CO, and light hydrocarbon gases (C_4 and below). This stream is passed through a standard methyldiethanol amine (MDEA) unit for CO_2 removal (a single CO_2 absorber and solvent regenerator), and the resulting CO_2 stream is dried and compressed to 150 bar for pipeline transport as a supercritical fluid to an injection site for storage. In combination with capture of CO_2 upstream, about 91 percent of the CO_2 produced at the plant is capture and stored.

Following the MDEA unit, the hydrogen-rich stream can be split into a recycle stream (with a maximum possible split about ¾ of the gas being recycled) that is returned to the F-T reactor, and a fuel gas stream. In the baseline scenario (Scenario 2), none of this steam is recycled. Instead, all of it is used for heating, for drying the biomass and coal, and for power generation. The power island consists of a steam generator, steam turbine generator, cooling water system, and associated auxiliaries. In the baseline scenario configuration, the power unit generates just enough electricity to meet all of the plant's onsite electricity needs.

Table 66 summarizes the performance for this CBTL facility (Tarka, 2009). Also shown are results, based on Tarka (2009), for similar plant designs utilizing biomass input fractions of 0 and 31 percent.

Table 66. Summary Characteristics of the Baseline Scenario CBTL Facility with Two Additional Feed Scenarios, Based on Tarka (2009)

CBTL Facility Parameter, Iron Catalyst	Fraction of Biomass Input (wt% as received mass basis)		
	0% *	16%	31%
Coal input (at 100% capacity), metric t/day, as-received	11,571	10,335	8,994
Coal input, MWth HHV	3,624	3,237	2,818
Biomass input (at 100% capacity), metric t/d, as-received	0	1,824	3,855
Biomass input, MWth HHV	0	355	751
Biomass energy input (% of total HHV energy input)	0	9.9%	21%
Total liquids production rate (at 100% capacity), bbl/d	30,000	30,000	30,000
Diesel production rate, bbl/d	20,562	20,575	20,575
Diesel energy content, MWth LHV (HHV)	1,254 (1,344)	1,255 (1,345)	1,255 (1,345)
Naphtha production rate, bbl/d	9,438	9,425	9,425
Naphtha energy content, MWth LHV (HHV)	537 (579)	537 (578)	537 (578)
Power generated, MW (equals process demand**)	270.4	271.7	272.2
Total plant energy efficiency, % HHV basis	53.0	53.5	53.9
CO_2 captured (at 100% capacity factor), metric t/d	14,501	14,501	14,497
CO_2 emissions from plant, metric t/d	1,436	1,338	1,412***

* Scaled linearly from NETL results for 50,000 bbl/d plant.
** Process power demand included de-baling of as-received switchgrass and grinding of the biomass to 1 mm or smaller particles.
*** From Tarka, 2010a, personal communication.

The results shown in Table 66 are for process designs that produce only diesel and naphtha as liquid products. Since the present analysis is focused on production of an F-T jet fuel, estimates have been made of how much F-T jet fuel might be produced if the liquid products from the upgrading section of the plant were separated into an F-T jet fuel fraction, a diesel fraction, and a naphtha fraction (see **Appendix A**). The result is a volume yield of F-T jet fuel of 53 percent of total liquids (Table 67). This yield seems reasonable by comparison to results of de Klerk (2008), who has made a detailed estimate of 77 percent volumetric output fraction of jet fuel from a low-temperature F-T unit designed to maximize F-T jet fuel production. For a plant designed with motor gasoline production in mind, the F-T jet fuel fraction ranges from 37 to 61 percent (de Klerk, 2008).

The results shown in the center column of Table 67 (for 16 percent biomass input) correspond to our baseline F-T jet fuel production scenario. In this Table, the energy content of the product streams was calculated using group contribution methods (as described in **Appendix B)** and the modeled carbon distribution discussed in **Appendix A.** This reflects the differences in the molecular makeup of the fuel products that result from the different processing scenarios considered in this work, and allows for consistent comparisons to be made between processing scenarios.

Carbon balance for the CBTL Facility is described in Table 68. As shown therein, carbon inputs to the CBTL Facility balance carbon outputs from the CBTL Facility, to within 0.01 percent for the 0 percent biomass scenario, to within 0.05 percent for the 15 percent biomass scenario, and to within 0.15 percent for the 31 percent biomass scenario. Additionally, Figure 29 and Figure 30, as well as Table 69 and Table 70 provide a summary of the F-T conversion process, as modeled for CTL (Scenario #1, 0 percent biomass) and for CBTL (Scenario #2, 15 percent biomass). These tables show temperature, pressure, mole flow, mass flow, volume flow, and enthalpy through the energy conversion facility.

Table 67. Summary Characteristics of Baseline Scenario CBTL Facility, with Adjustments to Liquid Fuel Production Estimates to Disaggregate F-T Jet Fuel Production

CBTL Facility Parameter, Iron Catalyst	Fraction of Biomass Input (% as-received wt basis)		
	0%*	16% (Baseline)	31%(Baseline)
Coal input (at 100% capacity), metric t/day, as-received	11,546	10,300	8,973
Coal input, MWth HHV	3,624	3,237	2,818
Biomass input (at 100% capacity), metric t/d, as-received	0	1,924	4,073
Biomass input, MWth HHV	0	355	751
Biomass energy input (% of total HHV energy input)	0	9.9%	21%
Total liquids production rate (at 100% capacity), bbl/d	30,000	30,000	30,000
F-T jet fuel production rate, bbl/d	15,939	15,939	15,941
F-T jet fuel energy content, MWth LHV (HHV)	984 (1056)	984 (1056)	984 (1056)
F-T Diesel production rate, bbl/d	10,769	10,769	10,769
F-T Diesel energy content, MWth LHV (HHV)	688 (739)	688 (739)	688 (739)
F-T Naphtha production rate, bbl/d	3,292	3,292	3,294
F-T Naphtha energy content, MWth LHV (HHV)	183 (198)	183 (198)	183 (198)
Power generated, MW (equals process demand)*	270.4	271.1	272.2
Total plant energy efficiency, % HHV basis	55	55	56
CO_2 captured (at 100% capacity factor), metric t/d	14,502	14,502	14,498
CO_2 emissions from plant, metric t/d	1,437	1,339	1,412
CO2, total generated (at 100% capacity factor), metric t/d	15,939	15,862	15,955
Number of gasifier trains	7	7	8
Number of F-T reactor trains	6	6	6
* Assuming no impact on power generation or consumption (compared with Table 66 results) with the different F-T upgrading process.			

Table 68. Summary Carbon Balance of the CBTL Facility

Carbon Flows	Units	Fraction of Biomass Input (% as-received wt basis)		
		0%*	16% (Baseline)	31%
Inlet Streams				
Coal Carbon	short tons C per day	8,114	12,063	6,307
Biomass Carbon	short tons C per day	N/A	1,425	1,810
Equivalent Acres to Produce Biomass	short tons C per day	N/A	182,096	231,233
Carbon Into CBTL Facility	short tons C per day	8,114	13,489	8,117
Carbon Out of CBTL Facility	short tons C per day	8,113	13,484	8,105
Intermediate Streams				
FT-Products (incl. naphtha)	short tons C per day	3,240	5,401	3,240
Non-Diesel Product Streams				
Naphtha (Equal to Naptha Produced@Avg. Petr. Refinery)	short tons C per day	978	1,627	976
Char/Slag	short tons C per day	81	135	81
CO_2 Storage	short tons C per day	4,361	7,268	4,359
Emissions				
Vented	short tons C per day	431	408	425

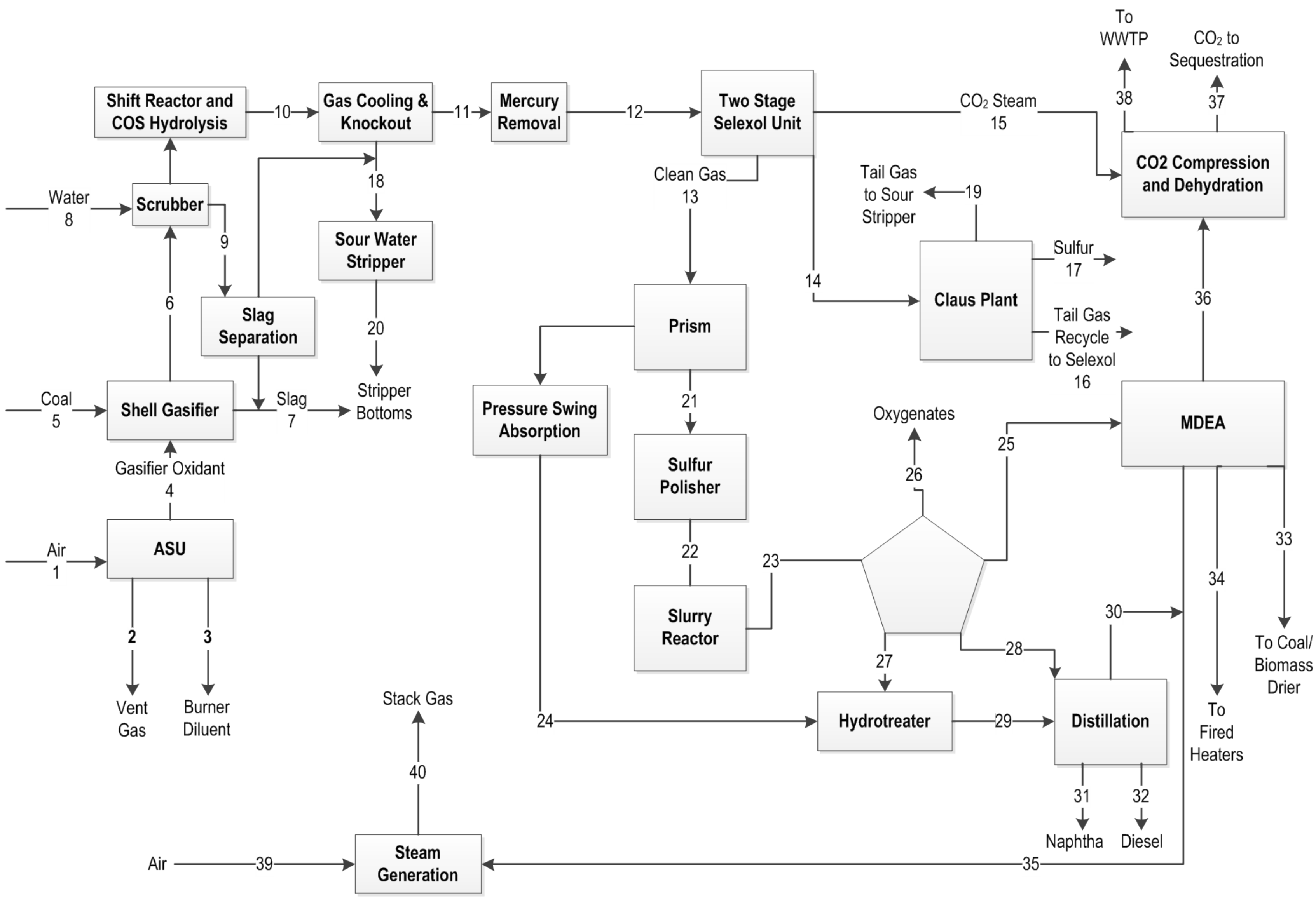


Figure 30. CTL Facility (Scenario #1, 0% Biomass) Stream Diagram

Table 69. CTL Facility (Scenario #1, 0% Biomass) Stream Values

Stream No.	Temperature (F)	Pressure (psi)	Mole Flow (lbmol/hr)	Mass Flow (lb/hr)	Volume Flow (cuft/hr)	Enthalpy (MMBtu/hr)
1	168.9	114.2	131,244	3,776,316	5,501,598	95.40
2	34.4	9.8	69,391	1,940,166	23,449,260	-100.80
3	54.0	33.7	34,827	976,744	3,642,000	3.00
4	120.6	399.0	26,369	838,548	279,503	19.98
5	84.0	8.8	-	992,346	-	-577.44
6	1,597.3	368.8	87,976	1,869,756	4,825,968	-1539
8	156.0	360.0	89,113	1,605,396	32,946	-10695
7	60.0	8.8	-	109,613	-	-2.52
9	247.4	358.8	1,771	31,907	733.8	-206.82
10	229.6	334.2	175,318	3,443,250	2,649,870	-12440
11	60.0	309.0	102,503	2,129,208	1,178,544	-5154
12	59.8	303.0	102,503	2,129,208	1,201,512	-5154
13	60.0	297.0	80,310	1,234,626	979,842	-1926
14	60.0	16.2	1,403	44,097	309,675	-52.56
15	105.4	1,328.8	15,747	693,018	26,521	-2693
16	66.0	329.7	556.8	21,414	5,348	-74.10
17	192.0	15.0	103.2	26,533	82.8	1.44
18	175.1	309.0	74,410	1,342,758	28,155	-8873
19	66.2	45.0	1,047	18,866	360.6	-128.8
20	148.2	21.0	75,400	1,359,972	100,849	-9059
21	300.0	294.0	77,828	1,229,550	1,655,286	-1704
22	126.7	294.0	104,047	1,695,108	1,542,180	-2273
23	244.0	294.0	56,374	1,695,108	1,045,722	-4076
24	60.0	285.0	1,987	4,007	25,412	0.30
25	60.0	294.0	45,443	1,184,124	535,855	-2938
26	60.0	294.0	10,030	182,326	3,510	-1236
27	272.0	294.0	613.8	291,430	7,868	-237.9
28	60.0	294.0	288.0	37,223	855	-29.70
29	194.1	294.0	2,011	295,436	94,993	-219.7
30	60.0	279.0	399.0	14,118	3,184	-16.92
31	46.2	8.8	918.0	96,038	2,208	-87.78
32	46.2	8.8	981.0	222,504	4,810	-194.6

Table 69. CTL Facility (Scenario #1, 0% Biomass) Stream Values *(Cont'd)*

Stream No.	Temperature (F)	Pressure (psi)	Mole Flow (lbmol/hr)	Mass Flow (lb/hr)	Volume Flow (cuft/hr)	Enthalpy (MMBtu/hr)
33	60.0	294.0	1,122	19,786	13,719	-17.46
34	60.0	294.0	496.2	8,754	6,070	-7.74
35	54.8	279.0	4,850	92,638	60,848	-86.10
36	63.0	1,328.8	14,509	638,502	13,680	-2514
37	84.8	1,328.8	30,256	1,331,520	37,921	-5208
38	49.7	12.0	27.60	493.8	9.6	-3.36
39	150.0	9.4	24,983	718,848	12,241,200	13.08
40	162.0	8.8	50,284	1,412,418	26,783,580	-773.3

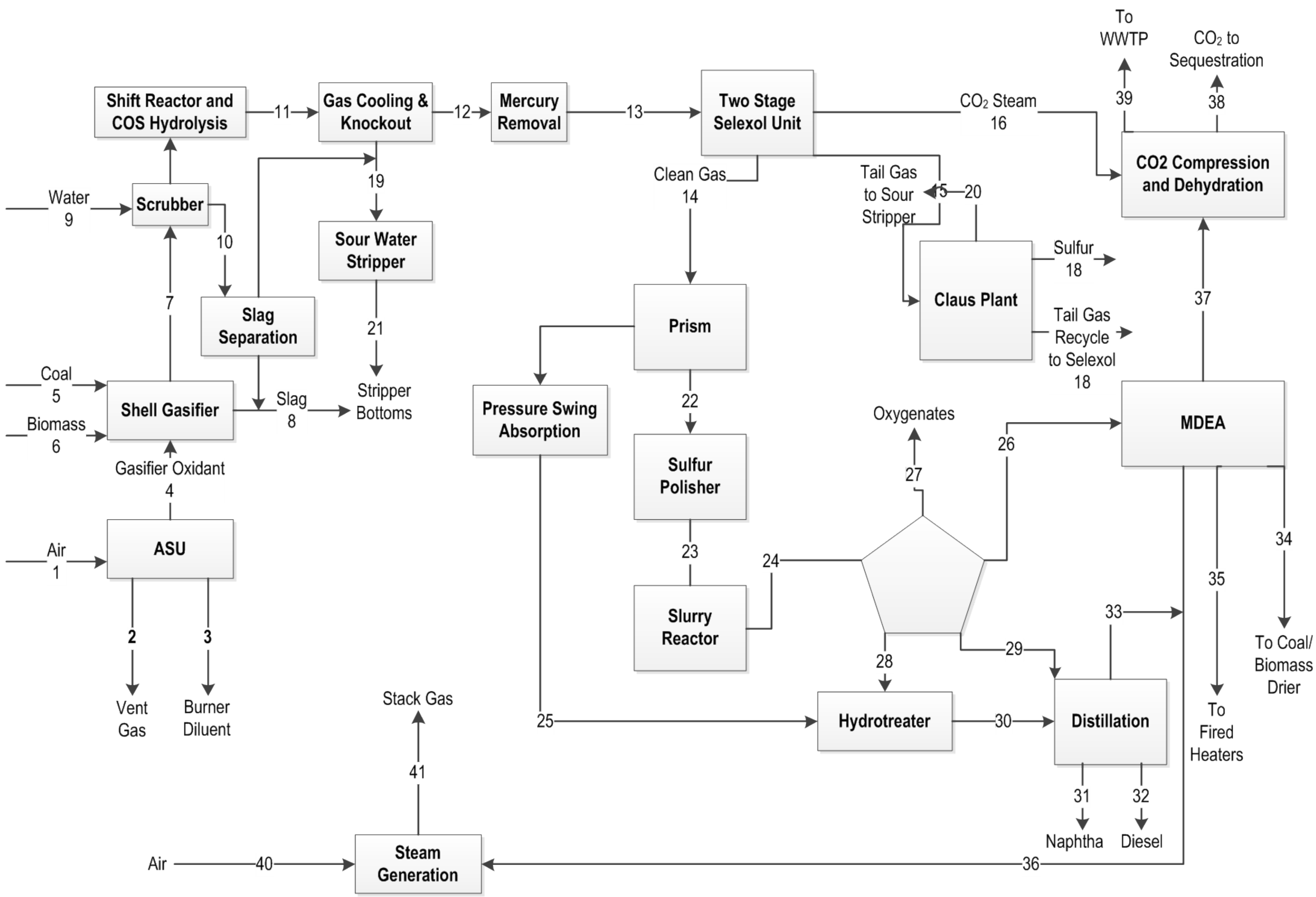


Figure 31. CBTL Facility (Scenario #2, 0% Biomass) Stream Diagram

Table 70. CBTL Facility (Scenario #2, 15% Biomass) Stream Values

Temperature (F)	Pressure (psi)	Mole Flow (lbmol/hr)	Mass Flow (lb/hr)	Volume Flow (cuft/hr)	Enthalpy (MMBtu/hr)	Enthalpy MMBtu/hr
1	168.9	114.2	127,552	3,670,098	5,346,852	92.7
2	34.4	9.8	66,526	1,859,994	22,478,100	-98.04
3	54.0	33.8	32,473	912,000	3,396,000	2.52
4	120.6	399.0	23,162	736,530	245,499	17.58
5	84.0	8.8	-	885,186	-	-515.0
6	84.0	8.8	-	158,177	-	-356.2
8	1,533.4	368.8	89,725	1,907,472	4,755,120	-1838
7	60.0	8.8	-	107,776	-	-3.72
9	156.0	360.0	87,346	1,573,572	32,293	-10483
10	247.1	358.8	1,771	31,905	733.2	-206.8
11	230.1	334.2	175,301	3,449,136	2,652,222	-12508
12	60.0	309.0	101,954	2,125,710	1,171,986	-5169
13	59.8	303.0	101,954	2,125,710	1,194,822	-5169
14	60.0	297.0	79,729	1,228,494	972,708	-1920
15	60.0	16.2	1,316	41,167	290,412	-52.0
16	105.4	1,329	15,727	692,154	26,488	-2690
17	66.0	329.7	551.4	21,395	5,287	-74.4
18	192.0	15.0	93.00	23,802	74.40	1.32
19	177.9	309.0	74,940	1,352,142	28,437	-8930
20	66.2	45.0	964.2	17,376	332.4	-118.6
21	148.2	21.0	75,842	1,367,754	91,652	-9113
22	538.6	294.0	77,247	1,223,424	2,319,540	-1476
23	297.0	294.0	105,889	1,747,632	2,239,908	-2064
24	245.0	294.0	58,259	1,747,632	1,084,476	-4082
25	60.0	285.0	1,987	4,007	25,412	0.3
26	60.0	294.0	47,344	1,237,374	558,541	-2952
27	60.0	294.0	10,015	182,056	3,505	-1235
28	272.2	294.0	613.8	291,027	7,870	-238.0
29	60.0	294.0	287.4	37,172	855.0	-29.7
30	194.2	294.0	2,009	295,034	95,032	-219.7
31	46.2	8.8	916.8	95,906	2,205	-87.7
32	46.2	8.8	981.6	222,200	4,813	-194.7

Table 70. CBTL Facility (Scenario #2, 15% Biomass) Stream Values *(Cont'd)*

Temperature (F)	Pressure (psi)	Mole Flow (lbmol/hr)	Mass Flow (lb/hr)	Volume Flow (cuft/hr)	Enthalpy (MMBtu/hr)	Enthalpy MMBtu/hr
33	60.0	279.0	398.4	14,099	3,179	-16.92
34	60.0	294.0	1,129	20,570	13,789	-16.92
35	60.0	294.0	474.6	8,647	5,797	-7.08
36	54.4	279.0	4,259	84,464	53,191	-74.76
37	63.0	1,328.8	14,530	639,389	13,680	-2517
38	84.8	1,328.8	30,257	1,331,544	37,907	-5208
39	49.7	12.0	27.00	490.2	9.00	-3.36
40	150.0	7.9	22,672	652,344	13,237,080	11.88
41	162.0	6.7	46,718	1,312,302	33,116,340	-713.2

6.1.1.5 Alternative Designs for F-T Jet Fuels Production

Table 66 and Table 67 show the variation in GHG emissions for different biomass input fractions. Additional alternative process designs may lead to different estimates for GHG emissions than for the baseline scenario design as well. This section contains data for alternative scenarios for producing F-T jet fuel that explore the impact of (1) a different F-T synthesis catalyst, and (2) different F-T synthesis and upgrading process configurations. We briefly discuss each of these scenarios here.

To explore impacts on GHG emission estimates of a different F-T catalyst, a separate process design for F-T jet fuel production using a cobalt F-T catalyst was developed, with a 14 percent by mass as-received biomass input fraction. The cobalt process configuration (Figure 32) differs from the iron-based design (Figure 29) following the gasifier section. Also, the molar ratio of H_2:CO in the feed to the F-T reactor must be higher than for an iron catalyst reactor. The molar ratio for this analysis is 2.1:1. Finally, the cobalt process is designed to accept switchgrass biomass with a moisture content of 15 percent. Therefore, the use of natural gas for switchgrass drying is not required for the cobalt process design.

When a cobalt F-T catalyst is used, the F-T reactor produces a high molecular weight, waxy product (F-T wax) rather than the mixture of F-T wax, F-T diesel, and F-T naphtha range products that are typical of a process using an iron F-T catalyst. As with the iron catalyst case, the wax from the cobalt catalyst F-T reactor undergoes upgrading via hydrocracking and isomerization to produce lighter products. There is flexibility in choosing the process configuration within the F-T synthesis and upgrading area. It would be designed to maximize investment return for some assumed market conditions. The upgrading section design shown in Figure 32, for which details are described by Allen, et al. (2010), represents a design that might be implemented under market conditions that promote maximizing F-T jet fuel production.

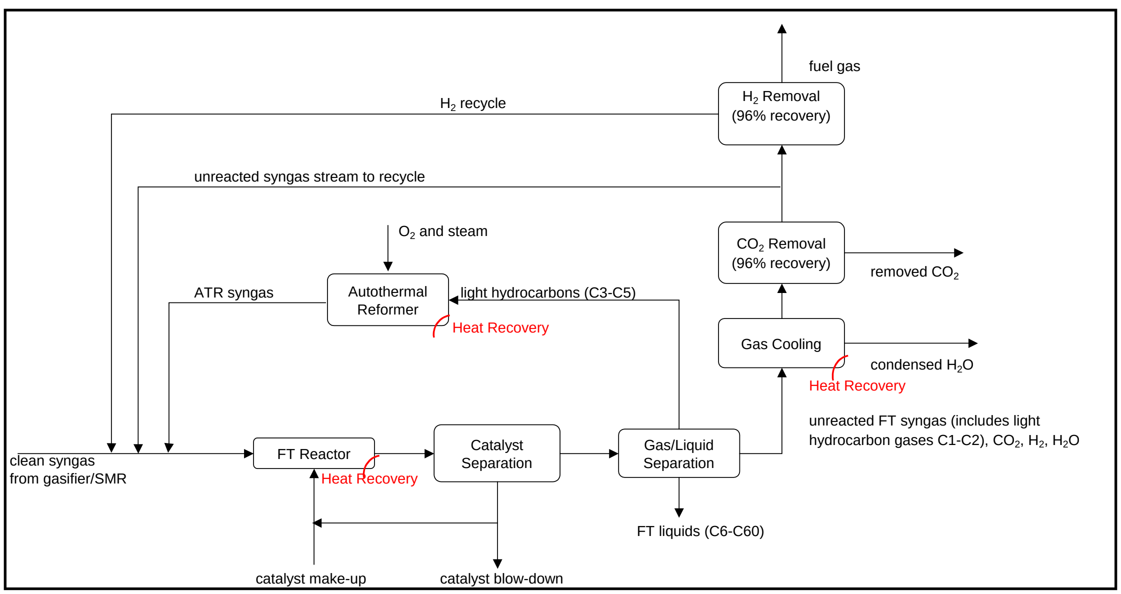


Figure 32. Alternative Processing Configuration for F-T Jet Fuel Synthesis (Cobalt Catalyst)

To provide a consistent basis for comparison with the iron-based catalyst systems shown in Table 67, the cobalt-based systems was designed to generate enough power onsite to meet all process power needs without any excess power for export. Detailed heat integration was not carried out as part of the design of the cobalt-based systems, but estimates of the potential steam turbine power generation using available heat and fuel-gas streams as inputs were made. Boiler feedwater pressurized to about 23 bar are preheated to about 220^{o}C in a syngas cooler, following the water gas shift, and in a raw F-T product cooler. The heat from the exothermic F-T synthesis process is used to evaporate the water, and the fuel gas streams available from the F-T refining area are burned to superheat the steam. Conservative estimates of power output for this design are on the order of 250 MWe. Although there are uncertainties involved in this estimate, including the assumption that the onsite power demands for a cobalt-based system design would be comparable to those for the iron-based system design (Figure 29) producing the same level of liquid fuels, the cobalt-based system was configured to be energy self-sufficient with no net power exports. The cobalt-based system was modeled with 50 percent recycle of the unreacted syngas stream as shown in Figure 32.

Also, in order to provide a consistent basis for comparison with the iron-based catalyst process, the same coal and biomass feeds were applied in both cases (Switchgrass and Illinois No. 6 coal). The coal feedstock studied by Allen et al (2010) is slightly different from the coal feedstocks of Tarka's iron-based catalyst research (2009). The as-received mass fraction of carbon in the coal (wet basis) for the CBTL facility described in Allen et al (2010) was assumed to be 0.71, while Tarka assumed an as-received carbon mass fraction (wet basis) of 0.6375. However, if the coal were dried to the same moisture content as the coal composition assumed by Allen et al (2010), the carbon mass fraction would be 0.70. It was assumed that the H_2:CO ratio and the overall CO yield in the gasifier output estimated by Allen et al. (2010) for the cobalt-based catalyst study would remain constant so long as the ratio of carbon in coal to carbon in biomass remained constant. Thus, the case that is described as 15 percent biomass (by mass, wet basis) in Allen et al. (2010) has been adjusted so that its coal input reflects the iron case feeds, and it is identified as 13 percent biomass in the descriptions of the cobalt case in this work. The higher heating value of the coal and biomass in the iron cases was applied to the cobalt cases as well.

The results in the column of Table 71 labeled "14 percent" are for the overall plant performance using a cobalt F-T catalyst and producing the same liquid products as in the iron F-T catalyst case (fuel gas, naphtha, F-T jet fuel, and diesel). Overall energy efficiency is 2-3 percent lower than for the iron catalyst case (the 15 percent 16 percent biomass case in Table 67), although this difference is likely due to differences in the details of the allocation of recovered heat and the use of fuel gas. The volumetric fraction of liquid output that is F-T jet fuel is 58 percent for the system using the cobalt F-T catalyst versus 53 percent for the iron F-T catalyst. This is expected since the cobalt catalyst produces more wax, favoring production of F-T jet fuel, while the iron F-T catalyst study sought to maximize production of diesel. The results in the column of Table 71 labeled "14 percent max SPK" are for a scenario where the hydrocracker is operated such that all hydrocarbons that are heavier than jet fuel are recycled and the only liquid products are F-T jet fuel and naphtha. Such a configuration maximizes the production of F-T jet fuel and may be desirable if the market value of F-T jet fuel is sufficiently high. As shown in Table 71, F-T jet fuel output is 36 percent higher with this process configuration than for the configuration where diesel is produced as well as naphtha and F-T jet fuel.

As shown in Table 71, the scenario where diesel and naphtha are produced in the wax upgrading section along with F-T jet fuel has 9 percent lower direct GHG emissions from the CBTL process than the scenario where only naphtha and F-T jet fuel are produced in the wax upgrading section. In addition to the variations in the wax upgrading section, which are depicted in Table 71, there are many other process configurations that could be considered.

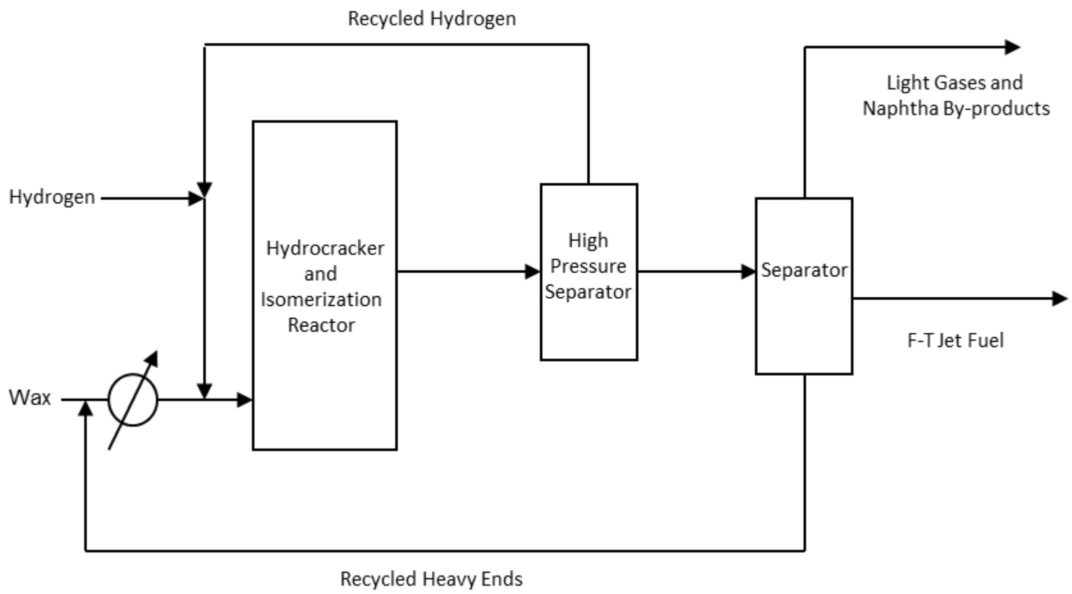


Figure 33. Configuration of Wax Upgrading Unit

For example, different levels of unreacted syngas leaving the F-T reactor could be recycled. In the primary cobalt F-T catalyst configuration (Figure 32), 50 percent of the unreacted syngas exiting the F-T reactor is recycled back to the reactor and the remainder is used to generate electricity and steam for onsite consumption. Increasing the recycle rate would decrease the amount of fuel gas available for electricity and steam production (which might require electricity and/or steam to be imported). Conversely, decreasing the recycling rate may generate excess electricity that could be exported to the grid.

Another processing scenario that could have been examined is varying the carbon number distribution of the products produced by the either the F-T iron or F-T cobalt catalyst by changing the F-T reactor conditions. A wide variety of carbon number distributions have been observed in F-T waxes (Shah et al., 1988). Examining the GHG footprints of these processing scenarios would provide additional information about the variability of the footprints depending on the details of processing configurations. These calculations were not performed since detailed data on the impact of reactor conditions on product carbon number distributions are not publicly available for commercial F-T reactors.

Table 71. Processing Scenarios Involving a Cobalt F-T Catalyst

CBTL Facility Parameter, Cobalt Catalyst	Fraction of Biomass Input (% as Received Basis)	
	14%	14% Max F-T Jet Fuel
Coal input (at 100% capacity), metric t/day, as-received	10,786	10,703
Coal input, MWth HHV	3.387	3,362
Biomass input (at 100% capacity), metric t/d, as-received	1,710	1,696
Biomass input, MWth HHV	315	313
Biomass energy input (% of total HHV energy input)	8.5%	8.4%
Hydrogen input, metric t/day	18	26
Hydrogen input, MWth LHV (HHV)	25 (29)	36 (42)
Total liquids production rate (at 100% capacity), bbl/d	30,000	30,000
F-T jet fuel production rate, bbl/d	17,363	23,595
F-T jet fuel energy content, MWth LHV (HHV)	1,079 (1,159)	1,465 (1,574)
F-T Diesel production rate, bbl/d	8,302	0
F-T Diesel energy content, MWth LHV (HHV)	530 (569)	0
F-T Naphtha production rate, bbl/d	4,335	6,405
F-T Naphtha energy content, MWth LHV (HHV)	242 (261)	358 (386)
Power generated, MW (equals process demand)	-	-
Total plant energy efficiency, % HHV basis	53%	53%
CO_2 captured (at 100% capacity factor), metric t/d	14,697	14,581
CO_2e emissions from F-T processing, metric t/d	1,366	1,490
CO_2, total generated (at 100% capacity factor), metric t/d	16,062	16,071

6.1.1.6 Key Factors Affecting CBTL System Performance

The following text provides a discussion of the key factors that are expected to affect the performance of the CBTL system. Herein, the performance of the CBTL facility is primarily dependent on process configuration, technology choices, and feedstock choices.

Process configuration choices, particularly the choice between fuels production versus poly-generation of fuels and electricity, can have some of the largest performance impacts, as greater levels of power production will reduce the overall efficiency of the facility as compared to a facility that focuses on fuels production. Other choices also impact performance, such as the choice to 1) compress CO_2 for transport and sequestration, 2) reform all or none of the light ends produced in the FT system for recycle to the reactor, 3) import electricity for plant efficiency, and 4) use combustion turbines for power generation rather than a direct-fired boiler. A syngas recycle configuration was utilized in this study to maximize fuels production, and only enough electricity is generated as is needed for auxiliary plant equipment. A direct-fired boiler is used for power generation, although later studies show that the use of a combustion turbine could be beneficial.

Technology choices used throughout the CBTL facility are far too myriad to be discussed here. The choice of a particular technology often has as much to do with the Engineering, Procurement, and Construction (EPC) company, other technologies utilized at the facility which have been proven to integrate well with the technology in question, operator familiarity with particular technologies, or even site-specific issues, as anything. Similarly, other performance trade-offs exist, which may result in a lower plant efficiency. A prime example is the use of air-

blown water cooling units (as opposed to evaporative cooling towers) in order to lower water consumption but at an efficiency penalty.

Feedstock choices can also impact performance. Biomass feedstocks are typically higher in moisture content than coal, and therefore require more drying prior to gasification, resulting in a net reduction in efficiency. Biomass also typically requires more energy-intensive grinding processes than coal. Lower rank coals can also negatively impact plant performance due to increased drying requirements as well as increased levels of inerts.

Outside of the areas listed above, opportunities exist for CBTL facility performance to improve through lessons learned via demonstration and deployment, as well as through integrating advanced technologies that are coming to the market. Improvements in areas such as combustion turbines, gasification, gas clean-up, and F-T reactor design have the potential to improve not only the efficiency, but also the economic performance of these facilities.

6.1.1.7 Key Modeling Variables

The results for the operation of the CBTL facility were generated using ASPEN models of the CBTL process. Because the ASPEN simulations impose atom, mass, and energy balances on the process configuration, a change in a processing parameter, such as the fraction of syngas recycled to the F-T reactor (50 percent in the baseline cobalt reactor scenario), influences the values of all other streams. Thus, it is not possible to assume that process variables are independent, and a Monte Carlo simulation of the uncertainties in GHG emissions, based on uncertainties in independent input parameters, cannot be performed for the CBTL process. While the CBTL process could not be parameterized, the Aspen model was modified to determine the inputs and outputs for five different configurations of the CBTL (i.e., five different operational scenarios for the CBTL facility). These five scenarios allow GHG emissions for different configurations of the CBTL to be compared. Uncertainty analyses for LC Stage #3a were based on a combination of scenario analyses and a sensitivity analysis of parameters that could be varied without influencing other process parameters (e.g., the fraction of CO_2 exiting the Selexol unit, and the GHG emissions associated with construction of the CBTL facility).

In Table 72, the best estimate, minimum value, maximum value, and most likely value are presented for the amount of CO_2 captured per kg of F-T jet fuel produced. The best estimate is around 91 percent of the total CO_2 generated in the CBTL facility, which is the target for the design of the CBTL. Since this is a design parameter, it was assumed the CBTL facility would be operated to capture 91 percent or more of the CO_2 generated. However, it is possible that an actual CBTL facility will not quite meet the design target. It is also possible that an operating CBTL could exceed the design efficiency. Therefore, it was assumed that the actual capture efficiency could be 1 percent lower or higher than the best estimate. Table 72 also provides the best estimate, minimum value, maximum value, and most likely value for variables used to assess the GHG emissions from construction of the CBTL facility. These results indicate that precise knowledge of CBTL process parameters will be required to precisely estimate GHG emissions.

While the CBTL process was not parameterized to create uncertainty estimates, as described in previous sections, multiple scenarios were evaluated to provide an indication of the range of variability that could be associated with a variety of feasible CBTL configurations.

Table 72. Key Modeling Variables for the Baseline Scenario CBTL Facility (LC Stage #3a)

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-CBTL Facility Operation							
CO_2 Captured (Scenario 1)	kg/kg F-T jet fuel	7.6	7.5	7.7	7.6	Uniform	Assumes minimum and maximum are +/- 1% of best estimate.
CO_2 Captured (Scenario 2)	kg/kg F-T jet fuel	7.6	7.5	7.7	7.6	Uniform	Assumes minimum and maximum are +/- 1% of best estimate.
CO_2 Captured (Scenario 3)	kg/kg F-T jet fuel	7.6	7.5	7.7	7.6	Uniform	Assumes minimum and maximum are +/- 1% of best estimate.
CO_2 Captured (Scenario 4)	kg/kg F-T jet fuel	7.1	7.0	7.1	7.1	Uniform	Assumes minimum and maximum are +/- 1% of best estimate.
CO_2 Captured (Scenario 5)	kg/kg F-T jet fuel	5.2	5.1	5.2	5.2	Uniform	Assumes minimum and maximum are +/- 1% of best estimate.
Input Parameters-CBTL Facility Construction							
Steel, Cold Rolled per kg F-T Jet Fuel Produced	kg/kg F-T jet fuel	2.95E-03	2.66E-03	4.43E-03	2.95E-03	Triangular	Assumes that material use is -10% to +50% of best estimate
Steel, Pipe Weld., BF (85% Rec.) per kg F-T Jet Fuel Produced	kg/kg F-T jet fuel	2.53E-04	2.28E-04	3.79E-04	2.53E-04	Triangular	Assumes that material use is -10% to +50% of best estimate
Cast Iron Parts per kg F-T Jet Fuel Produced	kg/kg F-T jet fuel	4.81E-05	4.33E-05	7.22E-05	4.81E-05	Triangular	Assumes that material use is -10% to +50% of best estimate
Aluminum Sheet per kg F-T Jet Fuel Produced	kg/kg F-T jet fuel	2.96E-05	2.66E-05	4.44E-05	2.96E-05	Triangular	Assumes that material use is -10% to +50% of best estimate
Concrete, Mixed 5-0 per kg F-T Jet Fuel Produced	kg/kg F-T jet fuel	1.66E-02	1.49E-02	2.49E-02	1.66E-02	Triangular	Assumes that material use is -10% to +50% of best estimate
Diesel Used to Install CBTL Facility (NGCC Plant Proxy)	kg/year	1.41E+06	1.26E+06	2.11E+06	1.41E+06	Triangular	Assumes that diesel use is -10% to +50% of best estimate
Construction Period for CBTL Facility	Months	20	18	30	20	Triangular	Assumes that construction period is -10% to +50% of best estimate
Area of 30,000 bbl/d CBTL	Acres	40	36	50	40	Triangular	Assumes that area necessary is -10% to +25% of best estimate
Fraction of Installation Inputs and Outputs Assumed to Apply to De-Installation		0.10	0.05	0.25	0.10	Triangular	Assumed based on best engineering judgment

These scenarios include use of cobalt or iron F-T catalysts, and optimizing hydrocracking to produce jet fuel or to produce diesel. While any single fuel producer will likely employ a single processing configuration, these scenarios give a quantitative indication of the range of values that might be expected based on the five configurations modeled. The details are described in the results section.

6.1.2 Data Quality Assessment

The results of unit process data quality evaluation for LC Stage #3a are provided in Table 73. Data quality indicators and life cycle significance determinations are listed for each unit process included in the model of this stage.

Analysis of the life cycle uncertainty significance of processes shows that the construction process for the CBTL facility is slightly above the significance threshold for the jet fuel production life cycle.

The operation of the CBTL facility is of high significance (10.1 percent) in the baseline life cycle of jet fuel. Because quality scores for source reliability and completeness are low for the CBTL facility operation, a detailed explanation of quality indicator choices for Stage #3a is provided in Table 74.

Table 73. LC Stage #3a Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Lifecycle Significance of Process (%)
1	Coal and Biomass to Liquid Facility, Operation	4,4,2,2,3	10.1%
1	Coal and Biomass to Liquid Facility, Construction	2,2,3,2,3	0.17%

Table 74. LC Stage #3a Qualitative Assessment of Data Quality

Quality Metric	Qualitative Assessment of Stage-Level Data Quality
Source Reliability	SCORE varies from 1-4; a variety of data sources were used. This part of the assessment was done using process models that ensured mass and energy balances. However, since there are a limited number of commercial F-T units in existence with an even more limited number of commercial cobalt catalyst F-T units, important variables, such as yields of liquid fuels from synthesis gas, were in many cases estimated based on best available data and/or expert opinion and/or personal communication. Wax characterization assumed for the cobalt-catalyst F-T reactor was based on a wax produced in a bench scale reactor. There were no detailed wax characterization data for the iron catalyst F-T reactor and it was assumed to match the profile of known iron catalyst waxes. Data sources for gasifier yields and synthesis gas compositions were more readily available and are expected to be more robust than those used for the F-T columns. The data are primarily secondary in nature. Data were expected to represent an industry average except that the coal fed to the gasifier was specifically Illinois No. 6. Primary Data: Primary data (data directly from industrial scale integrated gasifiers and F-T synthesis processes) were not available. Analyses were based on process simulations, based on secondary data. Secondary Data: Tarka, Thomas J. "Affordable, Low-Carbon Diesel Fuel from Domestic Coal and Biomass", prepared for the Department of Energy, National Energy Technology Laboratory, 2009 available at: http://www.netl.doe.gov/energy-analyses/pubs/CBTL%20Final%20Report.pdf- Process design/configuration and characteristics for baseline CBTL facility, characteristics of coal and biomass feedstocks Allen, et al., 2010: Allen, D.T., Murphy, C., Rosselot, K.S., Watson, S., Miller, J., Ingham, J., and Corbett, W. "Characterizing the Greenhouse Gas Footprints of Aviation Fuels from Fischer-Tropsch Processing", Final report from the University of Texas to the University of Dayton Research Institute, Agreement No. RSC09006, February 9, 2010: Process configuration for F-T processing with a cobalt catalyst Shah, PP, GC Sturtevant, JH Gregor, MJ Humbach, FG Padrta, KZ Steigleder. Fisher-Tropsch wax characterization and upgrading, final report. US Department of Energy. Available through NTIS DE88014638. June 6, 1988.– characterization of iron catalyst wax, verification of hydrocracker model
Completeness	SCORE varies 1-4 No attempt was made to assess the statistical representativeness of the yield and product data for the gasifier and F-T reactor process units. Data for commercial processes tend to be proprietary and when they are published, reflect the performance of a single production unit operating under a specific set of conditions. Process configurations in ASPEN and other modeling tools included complete mass balances of all of the species. When calculating GHG emission estimates, it was assumed that combustion would be complete and the only carbon-containing combustion product would be CO_2.
Temporal Representativeness	SCORE 2 Secondary data collection for this assessment focused on finding the most recent data available in literature sources. Most sources are recent (<5 years old), with Shah et al. (1988) being an exception. Shah et al. (1988) was the only source of detailed wax and hydrocracker product characterization available. Tarka (2009) is a recent publication but relies on data that was collected over multiple years. The data found are expected to be representative of current conditions for at least some plants in use today.

Table 74. LC Stage #3a Qualitative Assessment of Data Quality *(Cont'd)*

Quality Metric	Qualitative Assessment of Stage-Level Data Quality
Geographical Representativeness	SCORE 2 GHG emissions for the average US electrical generation grid were applied in the sensitivity analysis. The coal fed to the gasifiers was assumed to be Illinois #6. Otherwise, data represent global industry standards.
Technological Representativeness	SCORE 1 to 3 Processing for the conversion of coal and biomass co-feeds to F-T liquids is relatively recent; however, F-T processing has been used in industrial settings since the 1940s. Even though the process is relatively mature, there are very few commercial installations, so industrial scale data are sparse. The technology assumed for the gasifier was based on the largest gasification unit using a coal biomass co-feed, which is used in an IGCC application. F-T processing was based on the current implementation of iron catalyst F-T chemistry, with adjustments made to reflect the use of a cobalt catalyst where appropriate.

6.1.3 Results

This section presents the life cycle GHG emissions for LC Stage #3a. Quantitative uncertainty analyses were not performed for LC Stage #3a, because only one operational parameter, the amount of CO_2 captured in the gasification process was allowed to be uncertain. However, five scenarios reflecting different operating configurations for the CBTL facility were examined allowing deterministic GHG emissions from the different scenarios to be compared. A sensitivity analysis was performed on the baseline scenario (Scenario 2) to examine the influence of the CO_2 capture efficiency and construction inputs on the calculated GHG emissions.

6.1.3.1 Deterministic Greenhouse Gas Emissions

The deterministic results for Stage #3a are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S3a.Summ, which presents the input flows, output flows (products and co-products), and GHG emissions for this stage. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the functional unit. Operations unit process references are provided in sheet S3a.UP.O.CBTLOp and construction unit process references are provided in sheet S3a.UP.C.CBTLCon. GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are also presented in this sheet.

Scenarios 1 through 3 involve the use of an iron F-T catalyst with an as-received feedstock comprised of 100 percent coal (wet basis) for Scenario 1, 84 percent coal and 16 percent switchgrass by mass for Scenario 2 and 69 percent coal and 31 percent switchgrass by mass for Scenario 3. Scenarios 4 and 5 involve the use of a cobalt F-T catalyst with a feedstock comprised of 86 percent coal and 14 percent switchgrass by mass. In Scenario 4, F-T diesel is generated as well as F-T jet fuel and F-T naphtha. In Scenario 5, the process is configured to maximize the production of F-T jet fuel, which reduces the production of F-T diesel to zero.

Table 75 through Table 79 presents the life cycle GHG emissions for Scenarios 1 through 5, respectively. In these tables, the GHG emissions are presented in terms of the reference flow for this stage, which is 1 kg of F-T jet fuel ready for transport from the CBTL facility. These tables present the total emissions of 1) non-biogenic carbon dioxide from operation and construction, 2)

biogenic carbon dioxide from operation and construction, 3) methane from operation and construction, 4) nitrous oxide from operation and construction, and 5) other GHGs from operation and construction. This last category, other GHGs, captures emissions from GHGs other than carbon dioxide, methane, or nitrous oxide, or emissions that are expressed in carbon dioxide equivalents, and cannot be differentiated into the primary GHGs. The second column in these tables presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the IPCC 2007, IPCC 2001, and IPCC 1996 estimates, respectively.

The total CBTL facility CO_2e emissions per kg of F-T jet fuel produced are highest for Scenario 3 (31 percent Switchgrass, Iron F-T Catalyst—790 g CO_2e/kg). The next highest CBTL facility CO_2e emissions are for Scenario 1 (0 percent switchgrass, iron F-T catalyst—770 g CO_2e/kg), followed by Scenario 4 (14 percent Switchgrass, Cobalt F-T Catalyst—760 g CO_2e/kg) and Scenario 2 (16 percent Switchgrass, Iron F-T Catalyst—730 g CO_2e/kg). Scenario 5 (14 percent Switchgrass, Cobalt F-T Catalyst, Maximize F-T Jet Fuel) is the lowest GHG emitter at 630 g CO_2e/kg.

As indicated in Table 75 through Table 79, operation of the CBTL facility contributes far more to life cycle greenhouse gas emissions than do construction activities. Operations account for about 98 percent or more of the total life cycle greenhouse gas emissions for LC Stage #3a, for all study scenarios. The emissions of methane and nitrous oxide are negligible compared to the emissions of non-biogenic CO_2. There are no emissions of biogenic carbon dioxide or the "other GHG" categories for LC Stage #3a.

Table 75. LC Stage #3a Scenario 1 (100% Coal, Iron Catalyst) GHG Emissions (per kg F-T Jet Fuel Ready for Transport)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/kg F-T Jet Fuel)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	760	760	760	760
Non-biogenic CO_2 – Construction	12	12	12	12
Non-biogenic CO_2 – Subtotal	770	770	770	770
Biogenic CO_2 – Operation	0.0	0.0	0.0	0.0
Biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Biogenic CO_2 – Subtotal	0.0	0.0	0.0	0.0
CH_4 – Operation	0.00	0.0	0.0	0.0
CH_4 – Construction	0.00	0.1	0.1	0.1
CH_4 – Subtotal	0.00	0.1	0.1	0.1
N_2O – Operation	0.000	0.0	0.0	0.0
N_2O – Construction	0.001	0.2	0.2	0.2
N_2O – Subtotal	0.001	0.2	0.2	0.2
Other GHG – Operation		0.0	0.0	0.0
Other GHG – Construction		0.0	0.0	0.0
Other GHG – Subtotal		0.0	0.0	0.0
Operation – Total		760	760	760
Construction– Total		12	12	12
Grand Total		770	770	770

Note: Subtotals and totals may not sum exactly due to rounding.

Table 76. LC Stage #3a Scenario 2 (16% Switchgrass, Iron F-T Catalyst) GHG Emissions (per kg F-T Jet Fuel Ready for Transport)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/kg F-T Jet Fuel)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	720.0	720.0	720.0	720.0
Non-biogenic CO_2 – Construction	12.0	12.0	12.0	12.0
Non-biogenic CO_2 – Subtotal	730.0	730.0	730.0	730.0
Biogenic CO_2 – Operation	0.0	0.0	0.0	0.0
Biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Biogenic CO_2 – Subtotal	0.0	0.0	0.0	0.0
CH_4 – Operation	0.01	0.2	0.2	0.2
CH_4 – Construction	0.00	0.1	0.1	0.1
CH_4 – Subtotal	0.01	0.3	0.3	0.3
N_2O – Operation	0.001	0.3	0.3	0.3
N_2O – Construction	0.001	0.2	0.2	0.2
N_2O – Subtotal	0.002	0.4	0.4	0.5
Other GHG – Operation		0.0	0.0	0.0
Other GHG – Construction		0.0	0.0	0.0
Other GHG – Subtotal		0.0	0.0	0.0
Operation – Total		720.0	720.0	720.0
Construction– Total		12.0	12.0	12.0
Grand Total		730.0	730.0	730.0

Note: Subtotals and totals may not sum exactly due to rounding.

Table 77. LC Stage #3a Scenario 3 (31% Switchgrass, Iron F-T Catalyst) GHG Emissions (per kg F-T Jet Fuel Ready for Transport)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/kg F-T Jet Fuel)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	780.0	780.0	780.0	780.0
Non-biogenic CO_2 – Construction	12.0	12.0	12.0	12.0
Non-biogenic CO_2 – Subtotal	790.0	790.0	790.0	790.0
Biogenic CO_2 – Operation	0.0	0.0	0.0	0.0
Biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Biogenic CO_2 – Subtotal	0.0	0.0	0.0	0.0
CH_4 – Operation	0.02	0.5	0.4	0.4
CH_4 – Construction	0.00	0.1	0.1	0.1
CH_4 – Subtotal	0.02	0.5	0.5	0.5
N_2O – Operation	0.002	0.6	0.6	0.6
N_2O – Construction	0.001	0.2	0.2	0.2
N_2O – Subtotal	0.003	0.7	0.7	0.8
Other GHG – Operation		0.0	0.0	0.0
Other GHG – Construction		0.0	0.0	0.0
Other GHG – Subtotal		0.0	0.0	0.0
Operation – Total		780.0	780.0	780.0
Construction– Total		12.0	12.0	12.0
Grand Total		790.0	790.0	790.0

Note: Subtotals and totals may not sum exactly due to rounding.

Table 78. LC Stage #3a Scenario 4 (14% Switchgrass, Cobalt F-T Catalyst) GHG Emissions (per kg F-T Jet Fuel Ready for Transport)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/kg F-T Jet Fuel)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	750.0	750.0	750.0	750.0
Non-biogenic CO_2 – Construction	11.0	11.0	11.0	11.0
Non-biogenic CO_2 – Subtotal	760.0	760.0	760.0	760.0
Biogenic CO_2 – Operation	0.0	0.0	0.0	0.0
Biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Biogenic CO_2 – Subtotal	0.0	0.0	0.0	0.0
CH_4 – Operation	0.00	0.0	0.0	0.0
CH_4 – Construction	0.00	0.1	0.1	0.1
CH_4 – Subtotal	0.00	0.1	0.1	0.1
N_2O – Operation	0.000	0.1	0.1	0.1
N_2O – Construction	0.001	0.2	0.2	0.2
N_2O – Subtotal	0.001	0.3	0.3	0.3
Other GHG – Operation		0.0	0.0	0.0
Other GHG – Construction		0.0	0.0	0.0
Other GHG – Subtotal		0.0	0.0	0.0
Operation – Total		750.0	750.0	750.0
Construction– Total		11.0	11.0	11.0
Grand Total		760.0	760.0	760.0

Note: Subtotals and totals may not sum exactly due to rounding.

Table 79. LC Stage #3a Scenario 5 (14% Switchgrass, Cobalt F-T Catalyst, Maximize F-T Jet Fuel) GHG Emissions (per kg F-T Jet Fuel Ready for Transport)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/kg F-T Jet Fuel)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	620.0	620.0	620.0	620.0
Non-biogenic CO_2 – Construction	8.2	8.2	8.2	8.2
Non-biogenic CO_2 – Subtotal	630.0	630.0	630.0	630.0
Biogenic CO_2 – Operation	0.0	0.0	0.0	0.0
Biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Biogenic CO_2 – Subtotal	0.0	0.0	0.0	0.0
CH_4 – Operation	0.00	0.0	0.0	0.0
CH_4 – Construction	0.00	0.1	0.1	0.1
CH_4 – Subtotal	0.00	0.1	0.1	0.1
N_2O – Operation	0.000	0.2	0.2	0.2
N_2O – Construction	0.000	0.1	0.1	0.1
N_2O – Subtotal	0.001	0.3	0.3	0.3
Other GHG – Operation		0.0	0.0	0.0
Other GHG – Construction		0.0	0.0	0.0
Other GHG – Subtotal		0.0	0.0	0.0
Operation – Total		620.0	620.0	620.0
Construction– Total		8.4	8.4	8.4
Grand Total		630.0	630.0	630.0

Note: Subtotals and totals may not sum exactly due to rounding.

6.1.3.2 Probabilistic Uncertainty Analysis

Probabilistic simulations were performed on the baseline scenario CBTL facility emissions to quantify the influence of uncertainty in the key variables presented in Table 72. In this evaluation, probabilistic simulations were performed for total life cycle GHG emissions using the IPCC 2007 global warming potentials. CO_2 equivalent emissions were calculated relative to the stage reference flow of 1 kg F-T jet fuel. Table 81 presents the statistics for the CO_2e emissions developed from the simulations. Figure 34 presents the cumulative distribution and probability density function for CO_2 equivalent emissions relative to the LC Stage #3a reference flow. In Figure 34, the vertical scale on the left is for the probability density function and the vertical scale on the right is for the cumulative distribution.

The CO_2 equivalent emissions relative to the reference flow range from 660 to 820 g CO_2e/tonne CO_2, with a median value of 740 g CO_2e/tonne CO_2, a mean of 740 g CO_2e/tonne CO_2, and a standard deviation of 45 g CO_2e/tonne CO_2. Eighty percent of the distribution lies between 680 and 800 g CO_2e/tonne CO_2, and the middle fifty percent of the distribution lies between 700 and 770 g CO_2e/tonne CO_2.

Table 80. LC Stage #3a: Probabilistic Uncertainty Analysis; Statistics for CO_2e Emissions

Statistical Parameter	Mass of GHG Emitted to Atmosphere (g CO_2e/kg F-T Jet Fuel) (IPCC 2007 GWP)
Minimum	660
10%	680
25%	700
Median (50%)	740
75%	770
90%	800
Maximum	820
Mean	740
Mode	690
Stand. Deviation	45

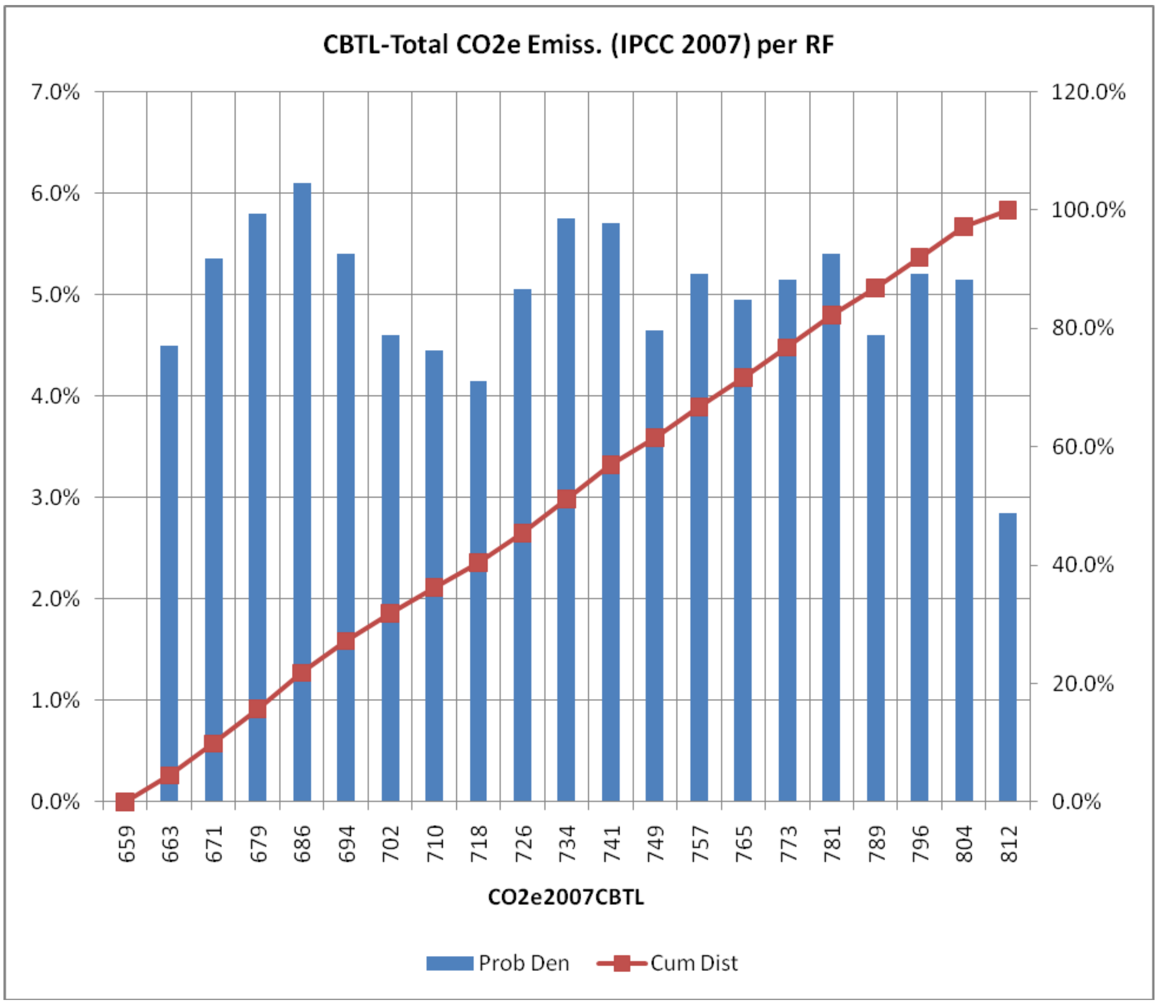


Figure 34. LC Stage #3a Baseline Scenario Probability Density Function and Cumulative Distribution of CO_2e Emissions (Using IPCC 2007 GWP) (per kg F-T Jet Fuel)

6.1.3.3 Sensitivity Analysis

To determine the influence of the amount of CO_2 captured for EOR on the calculated CO_2e emissions, a sensitivity analysis was performed. The sensitivity analysis was performed on Scenario 2 (the baseline scenario for the study). In the sensitivity analysis, the total CO_2e emission using the IPCC 2007 global warming potentials was calculated for each key variable in Table 72. Table 81 presents the results

Table 81. Sensitivity Analysis Results for Total CO_2e Emissions for Stage #3a (Using IPCC 2007 GWP) ($g\ CO_2e/kg$ F-T Jet Fuel Ready for Transport)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions ($g\ CO_2e/kg$ F-T jet fuel)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
CO_2 Captured for EOR	CO2_cap	kg/kg F-T jet fuel	7.62	7.54	7.7	811	659	152
Steel, Cold Rolled per kg F-T Jet Fuel Produced	Stl_Croll_kg	kg/kg F-T jet fuel	0.00295	0.00266	0.00443	734	739	5.03
Efficiency of Natural Gas Dryer	EffDryer_NG	MJ/MJ	0.625	0.5	0.75	738	733	4.84
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	734	736	1.41
Concrete, Mixed 5-0 per kg F-T Jet Fuel Produced	Concrete_5_0_kg	kg/kg F-T jet fuel	0.0166	0.0149	0.0249	735	736	1.38
Diesel Used to Install CBTL Facility (NGCC Plant Proxy)	Dies_InstNGCC	kg/year	1410000	1260000	2110000	735	736	0.803
Construction Period for CBTL	Con_Per_NGCC	Month	20	18	30	735	736	0.803
Area of 30,000 bbl/d CBTL	Area_CBTL	Acres	40	36	50	735	735	0.468
Fraction of Installation Inputs and Outputs Assumed to Apply to De-Installation	DeIn_Frac		0.1	0.05	0.25	735	735	0.243
Steel, Pipe Weld., BF (85% Rec.) per kg F-T Jet Fuel Produced	Stl_Pipe_BF85_kg	kg/kg F-T jet fuel	0.000253	0.000228	0.000379	735	735	0.174
Upstream CO_2 Emitted per kg Natural Gas Produced	NatGas_Upstr_CO2	kg CO_2/kg	0.0737	0.0701	0.0811	735	735	0.0429
Upstream CH_4 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CH4	kg CH_4/kWh	0.000835	0.000752	0.000919	735	735	0.0388
Cast Iron Parts per kg F-T Jet Fuel Produced	Cst_Iron_Pt1_kg	kg/kg F-T jet fuel	0.0000481	0.0000433	0.0000722	735	735	0.03
Upstream N_2O Emitted per kg Natural Gas Produced	NatGas_Upstr_N2O	kg N_2O/kg	0.00016	0.000152	0.000176	735	735	0.0277
Upstream CO_2 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CO2	kg CO_2/kg	0.718	0.683	0.754	735	735	0.0242
Aluminum Sheet per kg F-T Jet Fuel Produced	AlumSht1_kg	kg/kg F-T jet fuel	0.0000296	0.0000266	0.0000444	735	735	0.013

Table 81. Sensitivity Analysis Results for Total CO_2e Emissions for Stage #3a (Using IPCC 2007 GWP) (g CO_2e/kg F-T Jet Fuel Ready for Transport) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/kg F-T jet fuel)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream N_2O Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_N2O	kg N_2O/kWh	0.0000101	0.00000908	0.0000111	735	735	0.00558
Upstream CH_4 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CH4	kg CH_4/kg	0.004	0.0038	0.0042	735	735	0.00336
Upstream CH_4 Emitted per kg Natural Gas Produced	NatGas_Upstr_CH4	kg CH_4/kg	0.000118	0.000112	0.00013	735	735	0.00171
Upstream N_2O Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_N2O	kg N_2O/kg	0.000013	0.0000123	0.0000136	735	735	0.00013

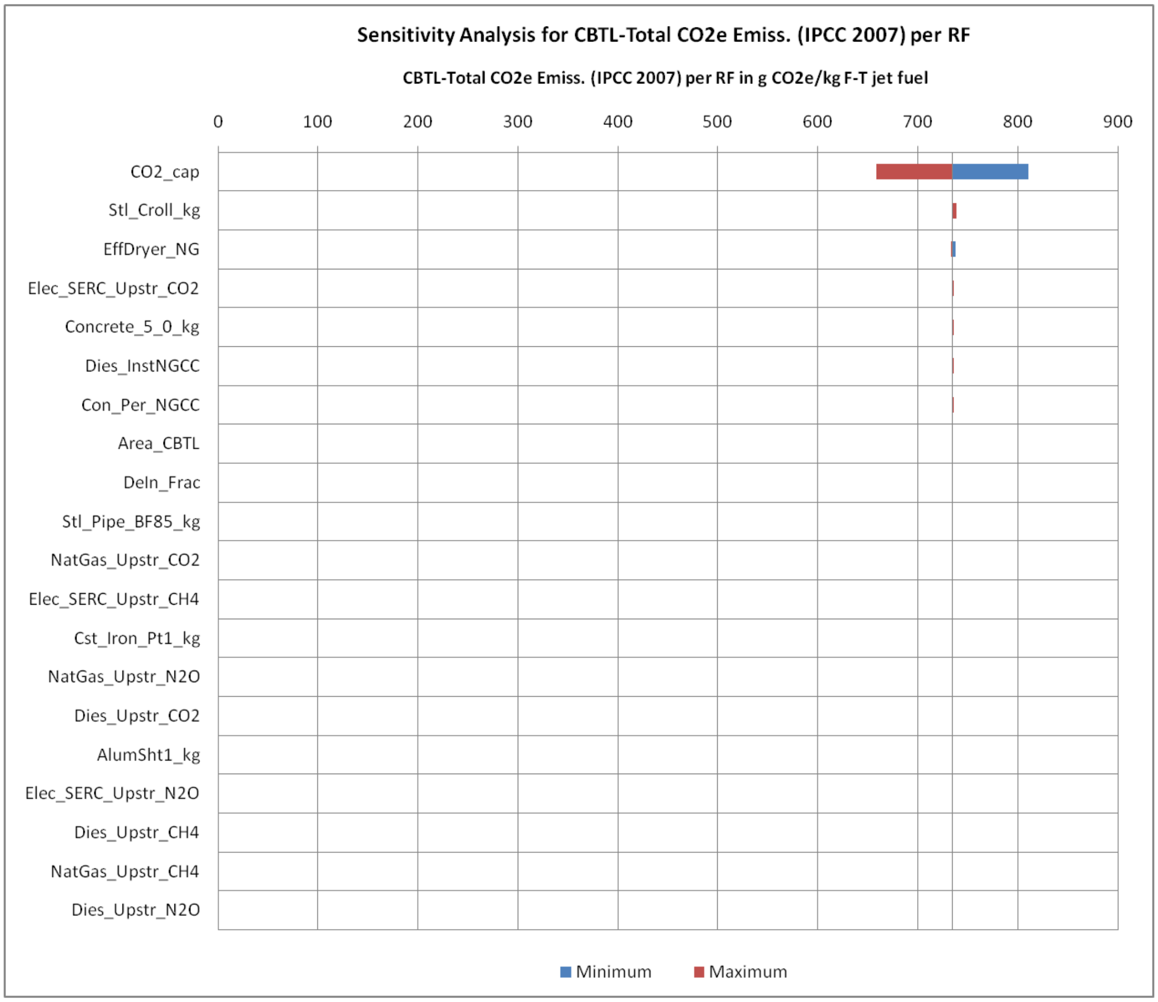


Figure 35. LC Stage #3a Sensitivity Analysis Results for Total CO_2e Emissions (Using IPCC 2007 GWP) (g CO_2e per kg F-T Jet Fuel Ready for Transport)

6.2 Carbon Dioxide Transport (LC Stage #3b)

This section describes characterization of the pipeline to deliver separated, dehydrated, and compressed CO_2 from the CBTL facility to an oil field where it will be used for CO_2-flood enhanced oil recovery.

6.2.1 Modeling Approach and Data Sources

Modeling of supercritical CO_2 pipeline transport involves various assumptions regarding pipeline length and characteristics, as well as leakage rate. Table 82 lists key assumptions made in modeling CO_2 transport from the CBTL facility to the enhanced oil recovery field.

Table 82. Key Assumptions for Supercritical CO_2 Pipeline Transport

Primary Subject	Assumption	Basis	Source
CO_2 Feed Rate from CBTL Facility	14.500 tonnes/day	CBTL Facility Model	NETL, 2009c
Base Pipeline Length	775 miles	Distance from CBTL facility to the Permian Basin, West Texas	Study Value
Actual Pipeline Length, (Accounting for Tortuosity)	861 miles	Distance from CBTL facility to the Permian Basin, Plus 10% Tortuosity Factor	Study Value
Pipeline Diameter	16 inch, nominal	Based on Required Pipeline Capacity for CO_2 Transport	Study Value
Pipeline Pressure/Head and Frictional Loss	3.2 MPa	Based on Pipeline Characteristics for Study	Study Value
Fugitive CO_2 Loss	48,500 tonnes/study period (30 years)	Based on Leakage Rate for Natural Gas Pipelines	Study Value

6.2.1.1 CO_2 Delivered to Pipeline

The CO_2 stream leaves the CBTL facility at 2,200 psig, entering the pipeline as a supercritical fluid. The facility provides approximately 14,500 of CO_2 tonnes/day (NETL, 2009c).

6.2.1.2 Characterization of CO_2 Pipeline Construction

Pipeline construction is characterized as originating from two sources: indirect emissions associated with construction of pipe and pump station materials, which require knowledge concerning the weight of the material and emissions from installation operations.

6.2.1.3 Estimation of Pipeline Length

CO_2 is assumed to be transported by pipeline from northeastern Missouri (near Kirksville, MO) to the Permian Basin, West Texas (near Midland, TX): a straight line distance of 775 miles (1250 km). Pipelines are not straight due to right-of-way issues and geographic obstacles. This is generally accounted for by applying a circuitry factor. As a base case, a circuitry factor of 1.1 as reported by the Congressional Budget Office (1982) for oil and coal water slurry pipelines was assumed for the CO_2 pipeline. Applying this factor, a CO_2 pipeline length of about 861 miles (1,386 km) was determined for this study.

6.2.1.4 Estimation of Pipeline Diameter

The CO_2 pipeline diameter was estimated by regressing CO_2 flow rate capacity versus pipeline diameter for a set of 12 pipelines operated by the Kinder-Morgan CO_2 Company, L.P. (Figure 36). Linear regression of these data gives a fit with correlation coefficient (R^2) of 0.958:

Equation 20 $D = 0.0324 \times C + 7.6305$

where:

D is the pipeline diameter in inches, and

C is the reported pipeline capacity in millions of standard cubic feet per day (MMSCFD).

This correlation was used to estimate appropriate pipeline diameter, with a 5 percent margin provided between plant flow rate and pipeline capacity.

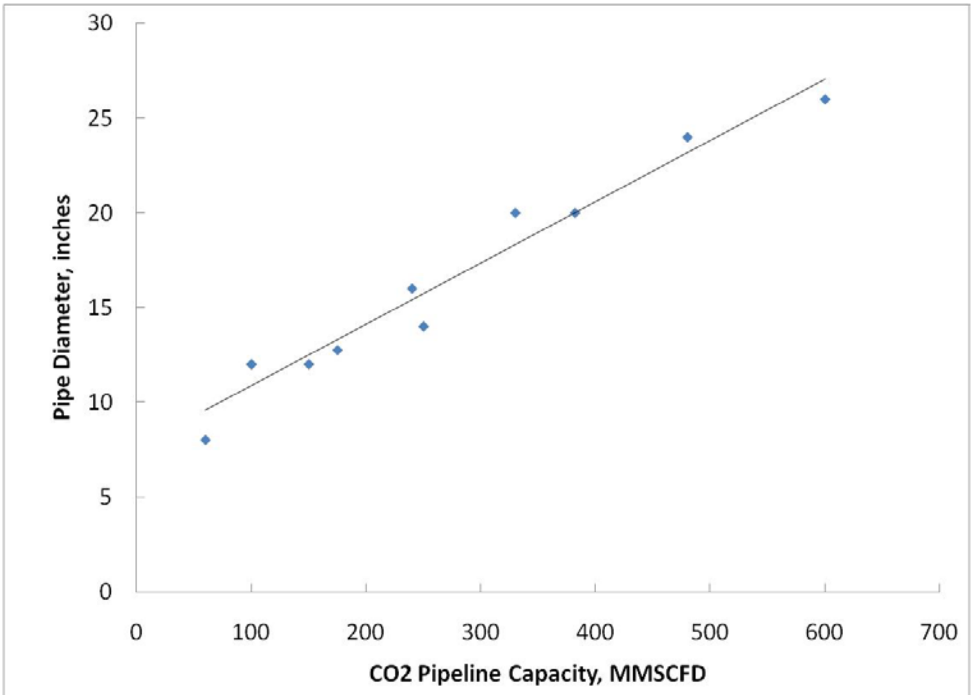


Figure 36. CO_2 Pipeline Diameter (Inches) as a Function of Pipeline Capacity (Millions of Standard Cubic Feet per Day)

6.2.1.5 Pipeline Material Requirements

The previously specified ANSI schedule 40 pipe (16-inch nominal with 15-inch internal diameter) has a unit mass of 116.08 kg/m. Thus, 161,000 metric tonnes of welded carbon steel will be required to construct an 861 mile pipeline. Based on the experience of pipelines moving dry CO_2 stream to CO_2-EOR fields in the Permian Basin, West Texas (Melzer, 2009; Fox, 2010) a 30-year service life was assumed with no pipeline replacement required.

6.2.1.6 Pump Station Material Requirements

Pumping station equipment mass was estimated based on a correlation between pump mass and horsepower rating taken from mud pump (used for drilling operations in the oil and gas industry) specifications (Sunnda Corporation) (Figure 37). Logarithmic regression provided a fit with correlation coefficient (r^2) of 0.97:

Equation 21 $M = 30333 \times \ln(HP) - 167{,}824$

where:

HP is pump horsepower rating, and

M is pump mass in pounds.

This correlation is valid in the range of approximately 590 to 2100 horsepower. While this type of pump is not appropriate for CO_2 boost compression applications, it is sufficient to provide an estimate of equipment material weight. Additional assumptions made to estimate electric motor and pump station concrete pad weight include the mass of electric motor being 25 percent of that of the pump, and the mass of concrete pad assumed as two times that of the estimated mass of

pump and motor. Upstream (cradle-to-gate) profiles for concrete and 316 stainless steel have been used to characterize the GHG emissions associated with cradle-to-gate activity manufacture of these process elements.

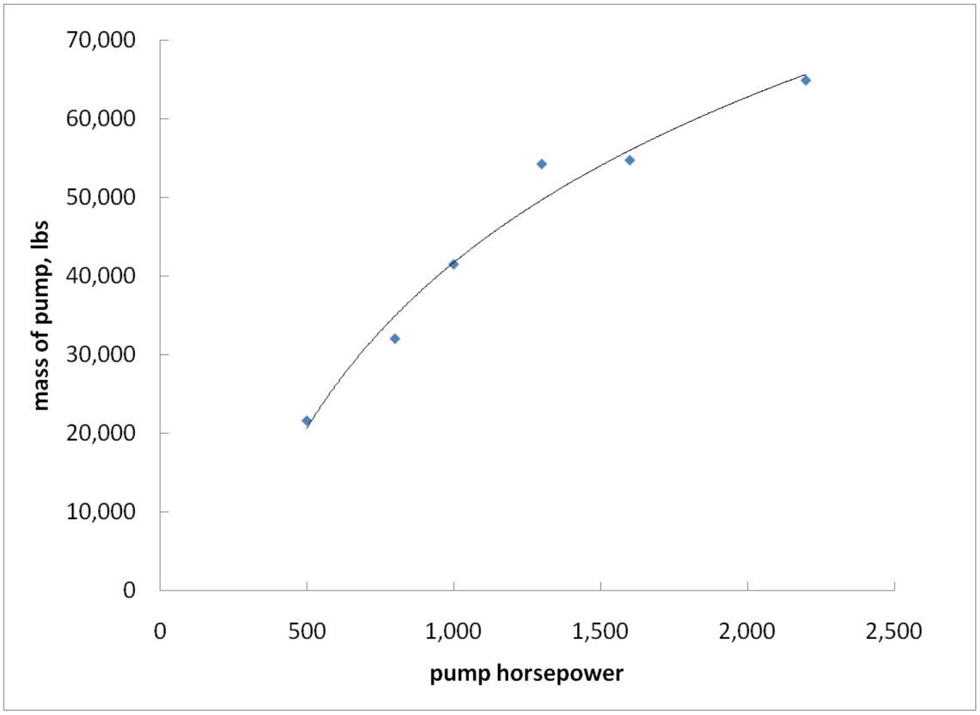


Figure 37. Mass of Pump as a Function of Pump Horsepower; Based on Well Drill Rig Mud Pumps

6.2.1.7 CO_2 Pipeline Installation/De-Installation

This unit process describes the fuel requirement and direct atmospheric emissions per mile of pipeline installed/de-installed. Diesel fuel usage and direct emissions were adapted from a report on installation of a natural gas pipeline, and deinstallation emissions are assumed to be 10 percent of installation emissions. Emissions from the manufacture of equipment are not considered in this unit process characterization.

6.2.1.8 Sources of GHG Emissions from CO_2 Pipeline Operation

GHG emissions associated with operation of the CO_2 pipeline are assumed to come from three sources: direct CO_2 emissions from fugitive loss, direct CO_2 emissions from intermittent venting of CO_2 during operation, and indirect GHG emissions associated with upstream activities required to produce and deliver electricity that is used in the CO_2 transport operations. Total operational GHG emissions have been estimated to be the sum of CO_2 equivalent emissions from these three sources. As discussed below, CO_2 head/pressure loss during transport is expected to be minimal. Therefore, booster pumps or other boost compression systems located along the pipeline would not be required, and operational emissions and energy requirements for such systems would not occur.

6.2.1.9 Estimation of Recompression Requirements

Pressure drop through the pipeline was estimated based on the sum of pressure drop from frictional forces and head loss due to change in elevation (from an elevation of approximately 900 feet at the CBTL plant to an elevation of approximately 2000 feet near Midland, Texas. Frictional losses were estimated based on the D'Arcy Weisbach equation:

Equation 22 $$\Delta p = \lambda \frac{L}{D_i} \times \frac{\rho \times v}{2}$$ where:

Δp = pressure drop

λ = dimensionless roughness number

L = length

ρ = density of the fluid

D_i = internal diameter

v = fluid velocity

For the current study with a volumetric flowrate of approximately 230 MMSCFD, an internal pipe diameter of 15 inches was selected (allowing for 5 percent capacity above this flow rate and rounding to the next largest specified standard pipe diameter). Pipeline length is 861 miles (about 1,370 km), mean density of CO_2 in the pipeline is estimated at 853 kg/m^3, and mean fluid velocity is estimated at 1.32 m/sec. Based on these values, a frictional pressure drop of 0.31 MPa (45 psi) is estimated. Head losses associated with change in elevation along the pipeline span were estimated to be the product of elevation change in meters times the mean fluid density (assumed to be 853 kg/m^3), and the standard gravity value 9.80665 m/s^2. Based on this calculation, headloss is estimated to be 2.9 MPa (420 psi). The sum of head loss and frictional pressure drop is estimated to be 3.2 MPa (470 psi). With this total loss of pressure, the pressure of delivered CO_2 is estimated to be 12 MPa (1730 psi) in the base case. Based on this characterization, boost compression was not required to transport the CO_2.

6.2.1.10 Venting Losses from Pigging Operations

Over the period of activity considered (30 years, per study design basis), it will be necessary to inspect the pipeline to verify its integrity, ensure that fugitive losses are minimal, and ensure the safety of workers and the public. CO_2 pipelines are "pigged" to check for corrosion once every 5 years. A pig is a device that is inserted into and moved through a pipeline to allow inspection of the internal surface of the pipe to verify its integrity. In pigging operations, the CO_2 pipeline is shut off upstream of the section to be inspected, and the pipeline downstream is allowed to bleed to a lower pressure limit (assumed to be 7.38 MPa). When the downstream pressure is at this limit, the downstream valve is closed and the contents of the pipeline section to be inspected (sections are typically 30 km in length) are vented to the atmosphere. The mass of CO_2 emitted to the atmosphere in these venting operations is calculated as the density of CO_2 at a pressure of 7.38 MPa at 70 °C times the volume of the pipeline section (pipeline internal cross-sectional area times section length). However, since inspection is conducted on the full pipeline, each inspection event will vent a volume equivalent to the full pipeline volume. The total vented volume is multiplied by the number of inspections carried out of the 30-year study period (30/5 years, or six inspection events).

6.2.1.11 Fugitive Losses of CO_2 in Pipeline Transport

A very small fraction of the transported CO_2 is expected to be released to the atmosphere during standard pipeline operations (IPCC, 2007). CO_2 pipelines are constructed from long sections of carbon steel that are welded together. Pigging stations with valves and flanges to facilitate shut off and access, respectively, are located at 30-mile intervals and these stations use highly impermeable seals (such as Viton seals) to ensure that CO_2 losses are minimal. A thesis by Wildboz (2007) assumes that leakage rate will be similar to that of natural gas in pipeline transport, and assumes a leakage rate of 0.026 percent per 1000 km of transport distance. This value is assumed for this study. Based on the assumed pipeline transport distance of 850 miles (about 1,370 km), leakage is estimated as 0.00026 * 1.37 percent of total transported CO_2, or 48,500 metric tonnes over 30 years of operation.

6.2.1.12 Catastrophic Leakage Events

Catastrophic events, including leakage of large volumes of CO_2 from CO_2 transport pipelines, are excluded from this study.

6.2.1.13 Key Modeling Variables

The key variables with respect to the emissions of GHGs during the construction and operation of a pipeline used to transport supercritical CO_2 to an EOR facility are presented in Table 83. For each variable, the best estimate is presented, along with the minimum value, maximum value, most likely value and the distribution assumed for the variable.

For most of the variables in Table 83, data were not readily available to estimate uncertainty, and/or to evaluate a most likely value. For these variables, the minimum and maximum values were assumed to be a multiple of the best estimate. If the uncertainty is low or moderate, the multiplier was 0.9 for the minimum value (i.e., 10 percent less than the best estimate) and 1.1 for the maximum value (i.e., 10 percent more than the best estimate). If the uncertainty is higher, the multiplier for the minimum value was lower and the multiplier for the maximum value was higher. Professional judgment was used to assess the level of uncertainty for each variable.

Table 83. Key Modeling Variables for Transport of Supercritical CO_2 to EOR (LC Stage #3b)

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-CO_2 Pipeline Transport Operation							
Fraction of CO_2 Lost per km Transported	1/km	2.60E-07	1.30E-07	3.90E-07	2.60E-07	Uniform	Assumes that fraction of CO_2 lost can be 50% higher or 50% lower than best estimate
Time Between Pigging Inspections	years	5.0	4.0	6.0	5.0	Uniform	Assumes that time between pigging can be 20% higher or 20% lower than best estimate
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	mi	775	698	853	775	Uniform	Assumes that point-to-point length of pipeline can be 10% higher or 10% lower than best estimate
Tortuosity Factor for Pipeline		0.10	0.05	0.20	0.10	Triangular	Assumes that tortuosity factor for pipeline can be 100% higher or 50% lower than best estimate
Input Parameters-CO_2 Pipeline Transport Construction							
Mass of Pipeline per Meter	kg/m	183	165	201	183	Uniform	Assumes that mass of pipe per m can be 10% higher or 10% lower than best estimate
Fraction of Installation Inputs and Outputs Assumed to Apply to De-Installation		0.1	0.05	0.25	0.1	Triangular	Assumed based on best engineering judgment
Diesel Fuel Used per Mile of Installed Pipeline	L/mi	9,200	8,280	10,120	9,200	Uniform	Assumes that diesel used per mile of installed pipeline can be 10% higher or 10% lower than best estimate

6.2.2 Data Quality Assessment

The results of unit process data quality evaluation for LC Stage #3b are provided in Table 84 Data quality indicators and life cycle significance determinations are listed for each of the two unit processes included in the model of this stage.

Analysis of the life cycle uncertainty significance of processes shows that the operation of a pipeline for transporting supercritical CO_2 is a significant contributor to the baseline life cycle GHG emissions of F-T jet fuel. This process scores low on the completeness metric because the data originates from a single operating pipeline. However, because the data from pipeline operation are measured over a 7-year period, it is considered of sufficient quality for the study. CO_2 emissions from the pipeline during operation are included in the sensitivity analysis.

The supercritical CO_2 pipeline construction process contains data with poor temporal representativeness for the current study. Based on a CO_2 pipeline constructed in California in 2001, the data with this low quality indicator include emissions from diesel combustion of construction equipment.

Table 84. CO_2 Transport (LC Stage #3b) Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Lifecycle Significance of Process (%)
1	Pipeline for Transporting Supercritical Carbon Dioxide, Operation	1,3,1,2,1	0.64%
1	Pipeline for Transporting Supercritical Carbon Dioxide, Construction	2,2,3,2,2	0.16%

6.2.3 Results

This section presents the GHG emissions for transporting supercritical CO_2 to the EOR facility. The GHG emissions for transporting CO_2 to the saline aquifer sequestration site are included in the total GHG emissions for LC Stage #3d. This section presents deterministic results, probabilistic uncertainty analysis results, and sensitivity analysis results.

6.2.3.1 Deterministic Greenhouse Gas Emissions

The deterministic results for Stage #3b are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S3b.Summ (when Scenario 1 for Managing Super Critical CO_2 has been chosen in sheet Scen.Control), which presents the input flows, output flows (products and co-products) and GHG emissions for this stage. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the functional unit. The operations unit process references are in sheet S3b.UP.O.PipeOp and construction unit process references are in sheet S3b.UP.C.PipeCon. GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are also presented in this sheet. Table 85 presents the life cycle GHG emissions for Stage #3b in terms of the reference flow for this stage, which is 1 tonne of supercritical CO_2 delivered to the EOR facility. This table presents the total emissions of 1) non-biogenic carbon dioxide from operation and construction, 2) biogenic carbon dioxide from operation and construction, 3) methane from operation and construction, 4) nitrous oxide from operation and construction, and 5) other GHGs from operation and construction. This last category, other GHGs, captures emissions from GHGs other than carbon dioxide, methane or

nitrous oxide, or emissions that are expressed in carbon dioxide equivalents and cannot be differentiated into the primary GHGs. The second column in the table presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the IPCC 2007, IPCC 2001, and IPCC 1996 estimates, respectively.

Approximately 23 percent of total GHG emissions for LC Stage #3b result from pipeline construction. This finding results from two key characteristics of the CO_2 pipeline: 1) the energy needed to push the CO_2 through the pipeline is attributed to LC Stage #3a, wherein CO_2 is compressed to sufficient pressure to enable transport under LC Stage #3b without additional pumps or energy input; and 2), the total length of pipeline constructed under LC Stage #3b is substantial (861 miles). Operational GHG emissions for this LC Stage are limited to leakage of CO_2 from the pipeline and pipeline maintenance activities (i.e., pigging). There are no operational losses of CH_4 or N_2O because no pumps or other equipment are used during operation of the pipeline.

Table 85. LC Stage #3b GHG Emissions (per Tonne CO_2 Delivered to EOR Field)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/tonne CO_2)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne CO_2) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne CO_2) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne CO_2) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	8,100	8,100	8,100	8,100
Non-biogenic CO_2 – Construction	1,900	1,900	1,900	1,900
Non-biogenic CO_2 – Subtotal	10,000	10,000	10,000	10,000
Biogenic CO_2 – Operation	0	0	0	0
Biogenic CO_2 – Construction	0	0	0	0
Biogenic CO_2 – Subtotal	0	0	0	0
CH_4 – Operation	0	0	0	0
CH_4 – Construction	2	52	48	43
CH_4 – Subtotal	2	52	48	43
N_2O – Operation	0	0	0	0
N_2O – Construction	0	31	31	32
N_2O – Subtotal	0	31	31	32
Other GHG – Operation		0	0	0
Other GHG – Construction		0	0	0
Other GHG – Subtotal		0	0	0
Operation – Total		8,100	8,100	8,100
Construction– Total		2,000	2,000	2,000
Grand Total		10,000	10,000	10,000

Note: Subtotals and totals may not sum exactly due to rounding.

6.2.3.2 Probabilistic Uncertainty Analysis

In an attempt to quantify the influence of uncertainty in the key variables presented in Table 83 on the calculated GHG emissions, probabilistic simulations were performed. In this evaluation, probabilistic simulations were performed for total life cycle GHG emissions using the IPCC 2007 global warming potentials. CO_2 equivalent emissions were calculated relative to the stage reference flow of 1 tonne of supercritical CO_2 delivered to the EOR facility. The CO_2e emissions relative to the reference flow range from 6.6 to 8.3 g CO_2e/kg coal, with a median value of 9.0 g CO_2e/kg coal, a mean of 9.4 g CO_2e/kg coal, and a standard deviation of 1.1 g CO_2e/kg coal. Eighty percent of the distribution lies between 8.3 and 11 g CO_2e/kg coal, and the middle fifty percent of the distribution lies between 9.0 and 10 g CO_2e/kg coal.

Table 86 presents the statistics for the CO_2e emissions developed from the simulations. Figure 38 presents the cumulative distribution and probability density function for CO_2 equivalent emissions relative to the LC Stage #3b reference flow. In Figure 38, the vertical scale on the left is for the probability density function and the vertical scale on the right is for the cumulative distribution.

The CO_2 equivalent emissions relative to the reference flow range from 6.6 to 8.3 kg CO_2e/tonne CO_2, with a median value of 9.0 kg CO_2e/tonne CO_2, a mean of 9.4 kg CO_2e/tonne CO_2 and a standard deviation of 1.1 kg CO_2e/tonne CO_2. Eighty percent of the distribution lies between 8.3 and 11.0 kg CO_2e/tonne CO_2, and the middle fifty percent of the distribution lies between 9.0 and 10.0 kg CO_2e/tonne CO_2.

Table 86. LC Stage #3b: Probabilistic Uncertainty Analysis; Statistics for CO_2e Emissions

Statistical Parameter	Mass of GHG Emitted to Atmosphere (kg CO_2e/tonne CO_2) (IPCC 2007 GWP)
Minimum	6.6
10%	8.3
25%	9.0
Median (50%)	9.0
75%	10.0
90%	11.0
Maximum	14.0
Mean	9.4
Mode	8.9
Stand. Deviation	1.1

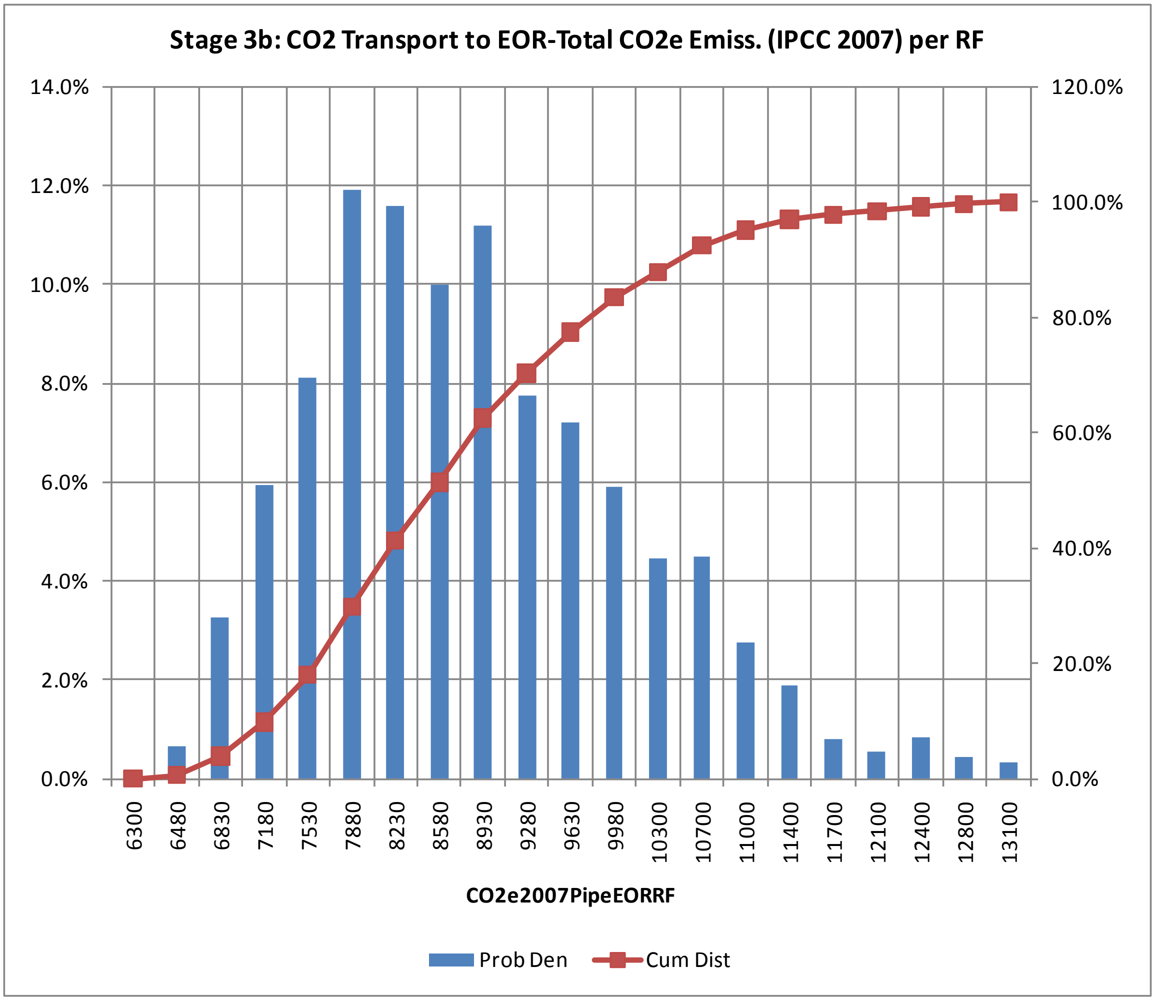


Figure 38. LC Stage #3b Probability Density Function and Cumulative Distribution of CO_2e Emissions (Using IPCC 2007 GWP) (per Tonne of CO_2 Delivered to the EOR Field)

6.2.3.3 Sensitivity Analysis

In the sensitivity analysis, the total CO_2e emission using the IPCC 2007 global warming potentials was calculated for each key variable. Table 87 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions. The Absolute Difference for each key variable is also shown, and key variables are listed from highest to lowest based on their Absolute Difference. The same results are presented graphically in Figure 39 in a tornado chart.

Three variables have a significant influence on the calculated CO_2e emissions. These variables are the time between pigging operations, the point-to-point length of the pipeline, and the pipeline tortuosity factor. These three variables all have about the same relative influence on the calculated CO_2e emissions. The remaining four variables have little influence on the calculated CO_2e emissions.

Table 87. Sensitivity Analysis Results (Using IPCC 2007 GWP) (g CO_2e/Tonne CO_2 Delivered to EOR Field)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/tonne CO_2)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Time Between Pigging Inspections	Pipe_pig_time	years	5	4	6	11500	8840	2610
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi	mi	775	698	853	9120	11200	2050
Tortuosity Factor for Pipeline	Pipe_tort		0.1	0.05	0.2	9610	11400	1820
Mass of Pipeline per m	Pipe_Mass_Per_m	kg/m	183	165	201	9960	10300	369
Fraction of CO_2 Lost per km Transported	Pipe_CO2FracFugEmiss_km	1/km	0.00000026	0.00000013	0.00000039	9960	10300	367
Diesel Fuel Used per Mile of Installed Pipeline	Dies_Used_mi	L/mi	9200	8280	10100	10100	10200	37.4
Fraction of Installation Inputs and Outputs Assumed to Apply to De-Installation	DeIn_Frac		0.1	0.05	0.25	10100	10200	34
Upstream CO_2 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CO2	kg CO_2/kg	0.718	0.683	0.754	10100	10100	3.38
Upstream CH_4 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CH4	kg CH_4/kg	0.004	0.0038	0.0042	10100	10100	0.47
Upstream N_2O Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_N2O	kg N_2O/kg	0.000013	0.0000123	0.0000136	10100	10100	0.0182

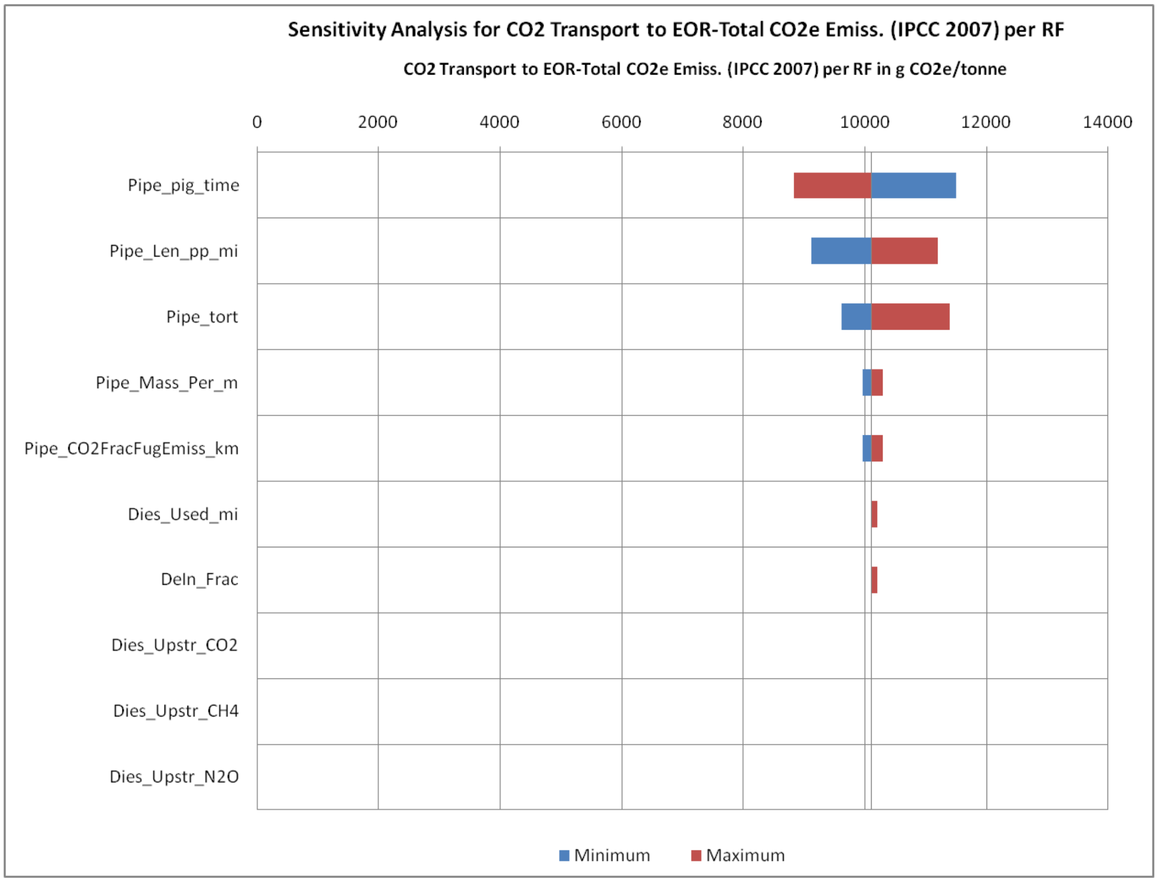


Figure 39. LC Stage #3b Sensitivity Analysis Results (Using IPCC 2007 GWP) (g CO_2e per Tonne CO_2 Delivered to EOR Field)

6.3 Carbon Management Strategy

This section describes the two carbon management strategies that are included in the study: 1) EOR using carbon dioxide injection and 2) sequestration of carbon dioxide into a saline geologic aquifer.

6.3.1 CO_2-EOR Operation (LC Stage #3c)

LC Stage #3c represents EOR occurring in the Permian Basin of Texas, based on a WAG carbon dioxide EOR injection strategy. Injection of carbon dioxide into oil-bearing formations reduces oil viscosity, thereby enhancing the fraction of total oil-in-place that can be recovered. Some fraction of carbon dioxide that is injected is later recovered, and subsequently reinjected, in support of continued EOR. Over time, the carbon dioxide remains within the EOR system, and is eventually sequestered in the oil bearing formation.

LC Stage #3c accepts and sequesters carbon dioxide that is delivered from the CBTL facility via the CO_2 transport pipeline (discussed previously). EOR operations result in the production of crude oil and natural gas liquids as products.

6.3.1.1 Modeling Approach and Data Sources

To estimate performance of CO_2-EOR operations, ***s***tream tube modeling was conducted for a typical Permian Basin-type reservoir in a 40-acre, 5-spot well pattern under a "best practices" scenario. Stream tube model results for a single well pattern operated under this "best practices" flooding scenario were scaled to the field level and field-level flows were used to estimate surface processing operations, infrastructure requirements, resource demands, and GHG emissions. Energy product yields were estimated from these field-scale operations. In the base case, it is assumed that loss of CO_2 from the flooding activities approaches zero and can be neglected. The influence of this assumption on estimated CO_2 equivalent emissions per barrel of crude oil produced has been considered through sensitivity analysis. The following sections provide a more detailed description of this approach.

6.3.1.1.1 Overview of Water Alternating Gas CO_2-EOR

Tertiary oil recovery is the recovery of formation oil that is residual to primary production and secondary water-flooding enhanced oil recovery. In Miscible CO_2-EOR, CO_2 flooding stimulates tertiary oil recovery by forming, above a minimum miscibility pressure, a miscible phase in which CO_2 and formation oil are mutually soluble. This miscible phase has lower viscosity than the crude oil, is more mobile, and can be produced to the surface more easily. In the Permian Basin of West Texas, most CO_2-EOR operations are miscible floods injecting CO_2 in alternation with water in a scheme commonly referred to as WAG injection. In WAG injection, water is used to reduce viscous fingering of free-phase CO_2, and drive the miscible CO_2/oil phase from the formation. By injecting CO_2 and water in alternation according to a prescribed WAG injection schedule, incremental oil recovery is enhanced.

Historically, lower volumes of CO_2 were applied in WAG injection paradigm to control the cost of CO_2 purchase. In recent years, CO_2-EOR WAG operations have trended toward higher CO_2 volume injection, with increasing CO_2 injection resulting in increased incremental oil production. Current "best-practices" for WAG operations is defined by injection in which the real volume (at formation temperate and pressure) of CO_2 injected is equivalent to the volume of pore space in the target area that was originally (before initiation of primary oil recovery) occupied by hydrocarbon. This is commonly termed one hydrocarbon pore volume (HCPV) of CO_2 injection, and will be referred to as such throughout this discussion.

6.3.1.2 Characterization of Single Well Pattern Performance

The CO_2-Prophet model is a screening tool commonly used by the oil and gas industry to predict enhanced oil recovery performance. It is a streamtube model that uses a finite difference routine to predict oil displacement for enhanced oil recovery by water, CO_2, or water-alternating-gas flooding (1986). Key model inputs include: properties of the oil-producing reservoir, properties of reservoir fluids, parameters describing relative permeability of different fluids in the reservoir, defined injection/production well pattern, and schedule and flow rates of water and CO_2 injection.

Average reservoir and reservoir fluid parameter values from a set of 228 Permian Basin, West Texas oil fields were taken from a proprietary database of large oil fields in the United States that is developed and maintained by Advanced Resources International, Inc. (ARI, Inc., 2009). Default fluid relative permeability values from the CO_2-Prophet model were assumed. A square well pattern with surface area of 40 acres, injection wells located at each corner and a pattern-

centered production well (4 acre, 5-spot well pattern) was specified. The schedule and rates of water and CO_2 injection define the "best practices" WAG CO_2-EOR injection scenario described above. The reservoir pressure is estimated to be well above the minimum pressure at which CO_2 is miscible in the formation with crude oil; this is estimated based on an empirical equation describing minimum miscibility pressure as a function of reservoir temperature and molecular weight of the crude oil pentanes plus fraction (Cronquist, 1978). Results of CO_2-Prophet model run for the described scenario are summarized in Figure 40, which reports flow rates for gaseous produced streams (CO_2 hydrocarbon gas) in millions of standard cubic feet per year, and Figure 41, which reports flow rates for produced liquid streams (water and oil) in thousands of barrels per year.

Based on the defined fluid injection schedule and the modeled field production rates, the amount of CO_2 geologically stored per pattern over the life of the flood, and the amount of excess byproduct brine produced per pattern over the life of the flood was calculated. Table 88 provides a summary of the cumulative performance over the life of a single pattern operated under the study base case. These single pattern results are scaled to the field scale as described in the subsequent section.

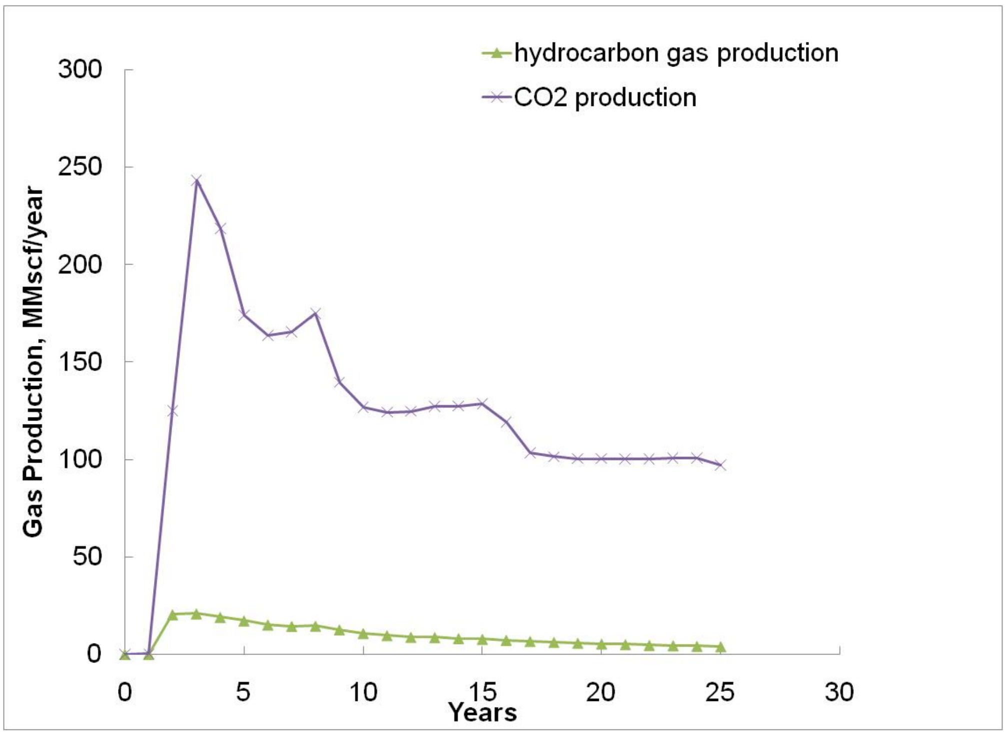


Figure 40. Summary of CO_2 and Hydrocarbon Gas Production Rates for a Single Average Permian Basin 40 Acre, 5 Spot Well Pattern Operated in Tapered WAG Configuration with Cumulative CO_2 Injection of One HCPV

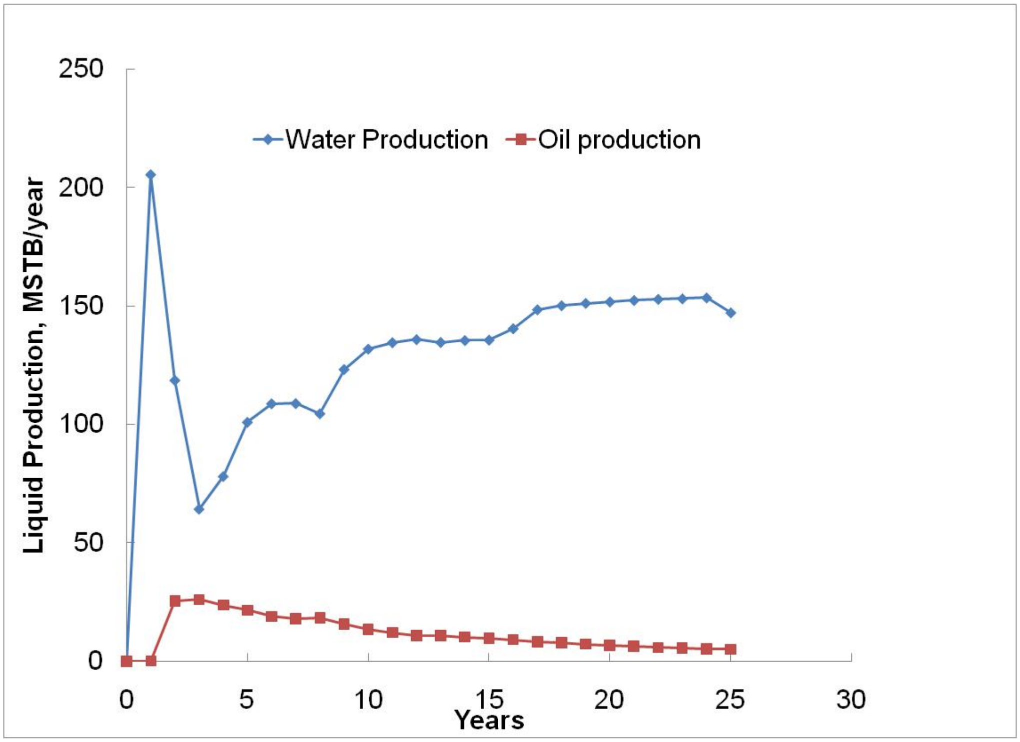


Figure 41. Summary of Water and Oil Production Rates for a Single Average Permian Basin 40 Acre, 5 Ppot Well Pattern Operated in Tapered WAG Configuration with Cumulative CO_2 Injection of One HCPV

Table 88. Summary Performance of Single Well Pattern as Operated in the Base Case*

Parameter	Value	Units
Cumulative CO_2 Injection per Pattern	1.0	HCPVs
Duration of Pattern Flooding	25	Years per pattern
Oil Recovery	301.7 (74%)	MSTB per well pattern (percent of original oil in place)
Cumulative Excess Brine Production	246.0	MSTB per well pattern
CO_2 Geologically Stored	70,000	Metric tonnes per well pattern
Tonnes CO_2 Stored per Barrel of Oil Produced	0.228	Metric tonnes CO_2 per barrel oil produced

MSTB: thousands of stock tank barrels

* Reported results are based on streamtube modeling of the base CO_2-EOR case as detailed elsewhere in this document: 1 HCPV WAG Permian Basin-type flood with 40 acre, 5 spot pattern configuration.

6.3.1.3 Scaling Single Well Pattern Performance to Field Level

Single pattern stream tube model results for best practices flooding in a typical Permian Basin-type reservoir were scaled to the field level to estimate surface processing operations and infrastructure requirements. The scale of CO_2-EOR operations is defined by the mass of CO_2 delivered to the field in the Permian Basin from the CBTL facility, which is a function of the amount of CO_2 input to the pipeline (varies by CBTL scenario) and loss of CO_2 in pipeline transport as described for LC Stage #3a. The number of well patterns assumed to be used to geologically store pipeline-delivered CO_2 is calculated as the cumulative mass of CO_2 delivered

over the 30 year study period times the amount of CO_2 stored per pattern (70,000 metric tonnes). Single pattern modeling reports a flood pattern duration of 25 years per pattern given the defined injection scenario and reservoir properties. Using the information, the number of pattern years of CO_2-EOR activity required to accommodate the required geologic storage of CO_2 was calculated. Surface operations and infrastructure elements required to inject CO_2 and water, and produce and process mixed fluid were scaled to meet the magnitude of geologic storage demand. Characterization of construction and operation of CO_2-EOR are detailed subsequently in this section.

6.3.1.3.1 Life Cycle Inventory Model

The reference flow used in characterizing performance of CO_2-EOR is 1 barrel of crude oil produced (delivered to pipeline for transport to a refinery). This analysis considers all phases of CO_2-EOR facility activity including: site characterization, site preparation, CO_2-EOR flood operation, well abandonment, and post-closure monitoring of CO_2 storage. Key assumptions used in characterization of surface processing operations include: electric-powered artificial lift of produced fluids; gas processing through liquid desiccant dehydration, cryogenic distillation of CO_2 from natural gas and natural gas liquids, and recompression of CO_2 for recycle to injection wells; and liquid processing with physical separation, water/oil emulsion thermal separation, separated oil and brine storage, and tank battery vapor recovery unit operation at 95 percent efficiency. Descriptions of elements considered in the characterization of CO_2-EOR activity are described for each phase of activity.

6.3.1.4 Site Evaluation and Characterization; Post Closure Monitoring, Verification, and Accounting of CO_2 Storage

The site surface and subsurface are assumed to be well characterized, as CO_2-EOR candidate fields will already have been perforated extensively in previous primary and waterflood secondary oil recovery operations. However, since the facility will be used for geologic storage of CO_2, it is assumed that airborne magnetic and lidar survey will be performed to identify abandoned well casings and establish a surface elevation map, respectively. In addition, a ground-based three dimensional seismic sounding is assumed to be required as a baseline assessment of the subsurface prior to large-scale CO_2 injection. The surface area to be surveyed was calculated as the area of all well patterns required to accommodate 30 years of CO_2 from the CBTL facility. Based on this area, an estimate of airborne and terrestrial survey grids and grid line miles was developed. It has been assumed that one legacy well that penetrates the target injection formation is located per square mile of survey area, and that that abandoned well is not reused in CO_2-EOR operations, but plugged with cement and abandoned prior to initiation of CO_2-EOR activity (US EPA, 2008). Direct emissions and diesel requirements for helicopter and seismic sounding equipment (thumper trucks) were calculated; indirect emissions associated with well-to-tank profile of diesel fuel used in these operations is included in the GHG emissions profile.

An estimate of post-closure monitoring, verification, and accounting of CO_2 storage is characterized by one additional airborne survey and one additional seismic survey. The GHG emissions profile is the same as that developed for site evaluation and characterization. Note that CO_2-EOR activity is assumed to be oil and gas business as usual and, as such, have not been subjected to the extensive CO_2 storage monitoring, verification, and accounting requirements that are being considered for large scale saline aquifer sequestration.

6.3.1.5 Facility Construction and Well Closure

The CO_2-EOR facility includes infrastructure elements associated with fluid injection and injectate transport, fluid production and produced fluid transport, and produced fluid processing (including processing of both liquid and gaseous fluid streams). Infrastructure elements associated with delivery of CO_2 to the oil field and those associated with transport of products from the site are considered in other unit process descriptions. A standard 5 spot well configuration with 40 acre pattern surface area was assumed for all well patterns.

Several CO_2-EOR process components are assumed to be pre-existing, as it is assumed that incremental oil was previously produced from the same field by secondary, water flood EOR. Pre-existing infrastructure elements that have been excluded from CO_2-EOR site construction characterization include: water tanks, crude oil tanks, EOR pattern (injection and production wells), produced fluid collection lines, and water distribution lines. New process elements for which construction has been considered include: CO_2 distribution lines, gas processing facility, CO_2 compressors, excess brine disposal wells, and tank battery vapor recovery units. While EOR pattern wells are pre-existing, it is assumed that they will require extensive workover prior to initiation of CO_2-EOR, and periodically throughout the period of operation.

For many of the newly constructed process elements, construction is characterized by estimating the mass of major construction materials with no installation requirements considered. Noteworthy exceptions are characterization of rig operation for well workover and new well construction for excess brine disposal wells, for which installation direct GHG emissions and resource demands have been considered. Closure of CO_2-EOR operations was characterized by estimating cementing rig operation direct emissions, cement production, and diesel fuel requirements for well plugging operations.

Upstream "cradle-to-gate" profiles for each energy and material input to the system were used, and documented in the F-T Jet Fuel Spreadsheet Model, to estimate indirect GHG emissions associated with CO_2-EOR activity, but occurring outside of the facility gate.

6.3.1.6 Operational Phase

CO_2-EOR operations have several direct GHG emissions sources, and a number of indirect GHG emissions associated with upstream profile of energy and material feedstocks and energy products associated with this activity. Figure 42 provides a simplified schematic of primary operations that comprise CO_2-EOR activity for the "best practices" WAG CO_2-EOR case. These unit operations fall into three general groups of activities: processing of the produced gas stream, processing of the produced liquid stream, and WAG injection into and fluid production from the geologic formation.

6.3.1.6.1 Fluid Injection and Production

Recovery of mixed fluid from the subsurface is assumed to require artificial lifting of fluids with an electric powered pump. Injection of brine used in WAG injection and excess (byproduct) brine that is disposed of through deep well injection is also assumed to be accomplished with electric powered pumping. In addition to the natural gas-fired compression of recycle stream CO_2 to 2000 psig accomplished in the gas processing plant, it is necessary to boost CO_2 pressure to 2200 psig by electric drive pumping prior to injection. Injected CO_2 will be a mixture of this recycle stream and pipeline supplied CO_2 (average ratio of purchased to recycled CO_2 over the life of a single well pattern is calculated to be 0.29), which is estimated to arrive at the CO_2-EOR

facility (Permian Basin, near Midland Texas) at a pressure of approximately 1740 psig. Electricity requirements are calculated based on average flow rates of each stream, and indirect emissions associated with electricity production and delivery to the CO_2-EOR facility are estimated based on a grid profile for electricity from the ERCOT Independent Service Operator NERC region, as described elsewhere.

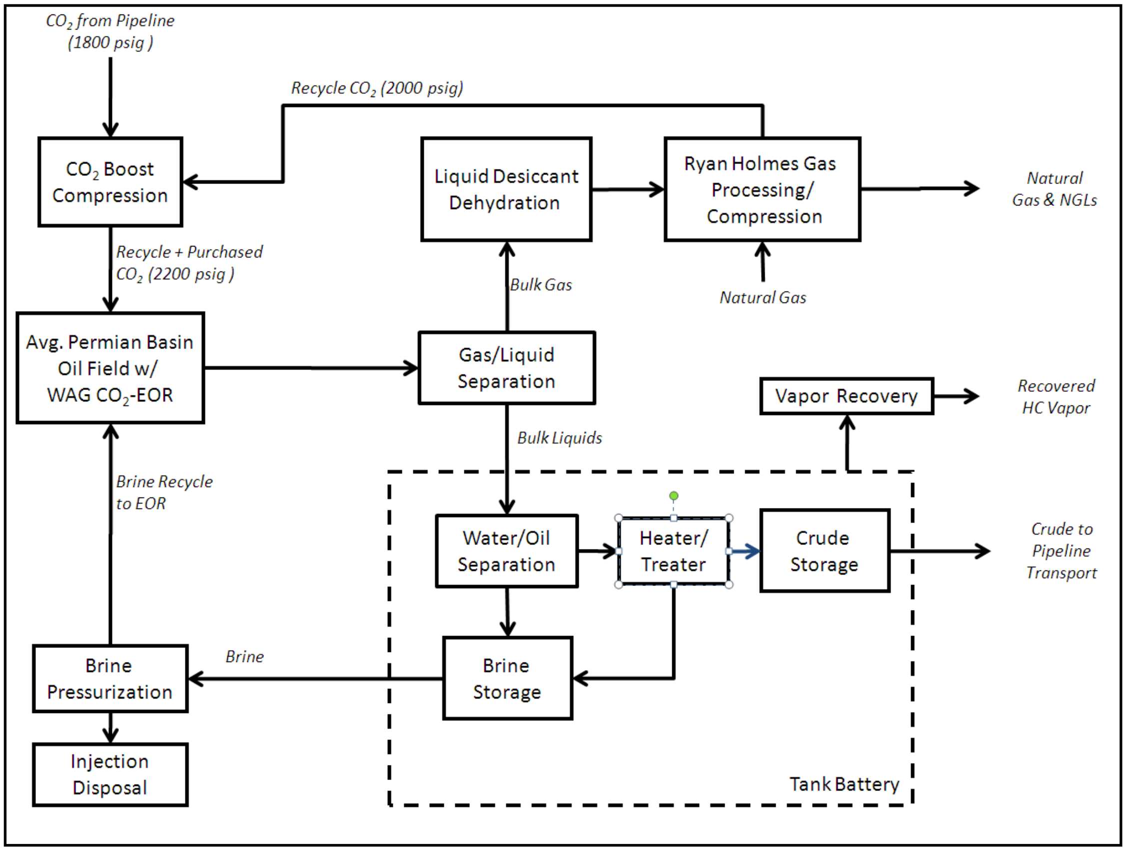


Figure 42. Simplified Schematic of Primary Operations that Comprise CO_2-EOR Activity in the Model "Best Practices" WAG CO_2-EOR Case

6.3.1.6.2 Gas Processing

Gas that is produced from CO_2-EOR operations contains CO_2, water vapor, and hydrocarbon gas. Gas processing is carried out to dehydrate bulk produced gas, separate CO_2 from produced oil-associated hydrocarbon gas, and recompress separated CO_2 in preparation for recycle to CO_2-EOR injection. Removing hydrocarbon gasses from CO_2 serves both to produce useable hydrocarbon coproduct streams (natural gas and natural gas liquids [NGL]), and to purify CO_2, and reduce the minimum pressure at which the recycled CO_2 stream forms a miscible phase with oil.

The amount of hydrocarbon gas contained in the total bulk gas that is separated from liquid (oil and water)fraction varies as a function of oil field gas composition and CO_2 application rate, and is generally higher in initial phases of CO_2-EOR production and tapers off as CO_2 breakthrough increases and total hydrocarbon production decreases.

Dehydration of the bulk gas stream is accomplished by exposing it to liquid desiccant (such as triethylene glycol) in a gas liquid contactor and regenerating liquid desiccant thermally. CO_2/hydrocarbon separation of the dehydrated stream is assumed to be carried out using Ryan-Holmes process for cryogenic distillative separation Process Systems International). Ryan Holmes process is a cryogenic process that is used in some CO_2-EOR operations to separate natural gas and NGLs from CO_2 stream by taking advantage of the difference in dew point between CO_2 and hydrocarbon fractions – selectively separating fractions as they condense at distinct points in a series of fractionation columns. Recovered CO_2 is recycled to CO_2-EOR operations where it is re-injected into the target reservoir to stimulate additional oil production. The primary energy demands and emissions from gas processing result from compression of refrigerant that is used to cool the separation column in the Ryan-Holmes process, and compression of separated CO_2 gas for recycle to WAG injection.

6.3.1.6.3 Characterization of Gas Processing Facility GHG Emissions

Gas processing facility emissions and resource requirements were characterized based on an operating CO_2-EOR carbon dioxide separation and gas processing facility - Whiting Oil and Gas Corporation's Dry Trail Gas Plant in Texas County, Oklahoma. Based on a plant operating permit renewal application submitted by Whiting (Milligan, 2007), this facility is designed to accept 45 MMSCFD low sulfur gas produced from CO_2-EOR flood operations, and processes that gas by dehydrating, compressing, and separating various fractions through the patented Ryan-Holmes cryogenic separation process (Process Systems International). Separated hydrocarbon gas is largely used on site to fuel gas processing plant operations, with the remainder delivered to pipeline for off-site sales. NGLs are collected to a storage tank and transported periodically offsite by truck for sales. Natural gas and diesel requirements and combustion emissions were estimated per gas processing plant-year for natural gas fired turbines, diesel backup generator, natural gas-fired hot oil heater (for dehydration liquid desiccant regeneration), and natural gas-fired compressor engines. In addition, fugitive emissions from plant valves and fittings were estimated using US EPA AP-42 fugitive loss factors. Hydrocarbon gas recovery performance was characterized as summarized below.

6.3.1.6.4 Estimating Separation Efficiency of the Ryan-Holmes Process

Partitioning of bulk gas constituents between fuel gas, NGL, and CO_2 recycle streams is adapted from a report by Ryan and Schaffert (1984). This report estimates methane recovery to fuel gas of 93 percent, CO_2 recovery to recycle stream of over 90 percent, and hydrogen, ethane, propane, and butanes fraction recoveries to NGL product of about 100 percent, 93 percent, 100 percent, and 99 percent, respectively. The average composition of bulk gas over the life of flooding of a single well pattern using the prescribed 1.0 hydrocarbon pore volume (HCPV) tapered WAG injection scenario was estimated based on ratio of cumulative CO_2 and hydrocarbon gas production rates and the average crude oil-associated gas composition from a set of 53 oil fields in the Permian Basin with API gravity values in the range of 32.5 and 37.5 °, as reported in a proprietary database of domestic oil fields (Nehring, 2009). Details of the composition of this average oil-associated hydrocarbon gas are provided in Appendix B. From this information, amount and energy content of recovered hydrocarbon coproducts (reported in HHV) were estimated.

6.3.1.6.6 Produced Liquids Processing

A tank battery is a collection of fluid flow lines, processing equipment, and storage tanks that is designed to process and store liquid received from one or more oil producing wells before the oil is transferred to a pipeline for sale. The primary factors influencing tank battery design are the flow rates and composition of liquid being processed. For purposes of this assessment it is assumed that fluid produced from 10 well patterns are collected to and processed in a single central tank battery facility. Liquids first pass through a liquid/liquid separator for bulk oil/water separation, and then the oil fraction is thermally treated in a natural gas-fired heater/treater to break water/oil emulsion. Separated water and oil are moved to storage tanks from which oil is transferred for sale and brine is pumped for reinjection in CO_2-EOR operations or deep well disposal. Hydrocarbon gasses released in the tank battery as working, breathing, and venting emissions are assumed to be collected by a vapor recovery unit (VRU).

The amount of CO_2 released from a tank battery is a function of the volume of oil passing through the tanks, the composition of the crude oil, the pressure at which separators discharge to the tank, the tank configuration, and seasonal daily temperatures. VRU performance has been characterized based on tank throughputs as estimated using volumetric flows to a single tank battery from ten producing wells. Working and breathing losses were estimated for oil storage tanks and heater/treater vessel using the US EPA TANKS version 4.0.9d. Flashing losses resulting from sudden decrease in gas solubility when fluid is transferred from higher to lower pressure and/or lower to higher temperature conditions are estimated using the Vazquez-Beggs equation. Vapor recovery efficiency of 95 percent by volume has been assumed. Following recovery, vapor is transported to a solid desiccant dehydration unit prior to sale or on-site use (Sidebottom and Richards, 2009). Amount of vapor recovered and emitted to the atmosphere were estimated based on average tank battery working, breathing, and flashing losses and VRU recovery efficiency, and amount of recovered energy was estimated based on a HHV of 2000 btu/scf.

6.3.1.7 Key Modeling Variables

The life cycle model for the EOR (both operation and construction) was developed outside the spreadsheet model used for the overall lifecycle analysis presented in this report. The output from the EOR lifecycle model could not be parameterized to allow petroleum and natural gas co-products and GHG emissions to be correlated with specific inputs to the EOR operation. Consequently, quantitative uncertainty analysis was not performed for LC Stage #3c.

From the perspective of GHG emissions, a key parameter is how much of the supercritical CO_2 delivered to the EOR from the CBTL is lost during the EOR process. Little is known about this parameter. The operators of EOR facilities have an economic incentive to lose as little supercritical CO_2 as possible during the EOR process, because supercritical CO_2 is an input to their process and they must pay for the supercritical CO_2 they use. Thus, it is believed that the amount lost is low and some industry experts believe the amount of supercritical CO_2 lost is negligible. For the uncertainty analysis and sensitivity analysis of the GHG emissions from the entire lifecycle, it was assumed that the amount of supercritical CO_2 lost during the EOR process is uncertain. As indicated in Table 89, the best estimate for the amount of supercritical CO_2 lost is 0.5 percent, with a minimum value of 0 percent and a maximum value of 1 percent. Table 89 also presents the uncertainty in variables associated with determining the GHG emissions from the EOR during construction activities associated with the EOR.

Table 89. Key Modeling Variables for Evaluating Uncertainty in Greenhouse Gas Emissions from EOR (LC Stage #3c)

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-EOR Operation							
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	kg/kg	0.005	0	0.01	0.005	Uniform	Assumes that fraction of CO_2 lost can be as low as zero and as high as 1% with a best estimate of 0.5%
Input Parameters-EOR Construction							
Diesel Used per Barrel of Crude Oil Extracted	kg/bbl	1.02E-01	9.17E-02	1.53E-01	1.02E-01	Triangular	Assumes that diesel use is -10% to +50% of best estimate
Concrete, Mixed 5-0 Used per Barrel of Crude Oil Extracted	kg/bbl	1.06E-01	9.54E-02	1.59E-01	1.06E-01	Triangular	Assumes that material use is -10% to +50% of best estimate
Steel, 316 Stainless Cold Rolled Used per Barrel of Crude Oil Extracted	kg/bbl	1.04E-02	9.35E-03	1.56E-02	1.04E-02	Triangular	Assumes that material use is -10% to +50% of best estimate
Type I Portland Cement Used per Barrel of Crude Oil Extracted	kg/bbl	1.89E-01	1.70E-01	2.83E-01	1.89E-01	Triangular	Assumes that material use is -10% to +50% of best estimate

6.3.2 Data Quality Assessment

The results of unit process data quality evaluation for LC Stage #3c are provided in Table 90. Data quality indicators and lifecycle significance determinations are listed for each of the two unit processes included in the model of this stage.

Analysis of the lifecycle uncertainty significance of processes shows that the EOR operation process is highly significant in the product life cycle. Given the significance of this process, a qualitative assessment of data quality is provided for each of the required indicators in Table 91.

Table 90. LC Stage #3c Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Lifecycle Significance of Process (%)
1	Enhanced Oil Recovery (EOR) Using Supercritical Carbon Dioxide, Operation	3,3,2,2,2	25.1%
1	Enhanced Oil Recovery (EOR) Using Supercritical Carbon Dioxide, Construction	3,3,2,2,2	0.18%

Table 91. LC Stage #3c Qualitative Assessment of Data Quality

Quality Metric	Qualitative Assessment of Stage-Level Data Quality
Source Reliability	Most data used in characterization of CO_2-EOR activity are considered to be of a secondary nature. Fluid injection and production rates were modeled using a model that performs screening-level prediction of CO_2-EOR flood performance for a single well pattern. Single well pattern data were scaled to the field level, and the magnitude of liquid and solid stream processing operations were scaled to field-level flow rates. To meet the regulatory requirement for determining the life cycle GHG emissions associated with alternative jet fuel production, this type of modeling-based data may be considered to be inadequate and site specific CO_2-EOR facility data may be required by the approving agency. For purposes of this case study, this model-based approach is considered to be acceptable. Source reliability of data is, therefore, considered to be adequate and is assigned an indicator score of 3.
Completeness	An effort was made to account for greater than 99% of all known mass and energy flows associated with CO_2-EOR activity in five phases of activity: site evaluation, construction, flood operation, site closure, and post-closure monitoring. However, without having demonstrated that all mass and energy flows are accounted for, it is not possible to verify that the aforementioned 99% minimum mass and energy accounting criteria have been satisfied. As such, these cut off criteria can serve only as a guide to evaluate if a system has been sufficiently described. A completeness indicator value of 3 is assigned.
Temporal Representativeness	Characterization of CO_2-EOR activity is believed to be representative of current best practices in the geographic region of interest. Reservoir data on which CO_2-EOR modeling is based are taken from a proprietary database that is regularly updated to reflect changes in remaining oil in place due to ongoing production activities. As such, temporal representativeness is considered to be fairly strong (estimated indicator score of 2)

Table 91. LC Stage #3c Qualitative Assessment of Data Quality *(Cont'd)*

Quality Metric	Qualitative Assessment of Stage-Level Data Quality
Geographical Representativeness	Characterization of CO_2-EOR is representative of current best practices in the Permian Basin, West Texas, USA. Gas processing operations included within this characterization reflect performance of a CO_2-EOR field gas processing facility in Texas County, Oklahoma; performance of this facility is expected to not be significantly different from a similar plant that would operate in West Texas. Geographic representativeness is, therefore, considered to be fairly strong (estimated indicator score of 2)
Technological Representativeness	Characterization is representative of CO_2-EOR applied in a tapered water-alternating-gas (WAG) injection scheme with cumulative application of one hydrocarbon pore volume of CO_2 per well pattern. This injection scheme is considered to be representative of current best practices in the Permian Basin of West Texas, although it should be noted that injection schedules are site or pattern-specific and based on knowledge and analysis of reservoir engineers and field operators. Gas processing characterization is based on data from a single Ryan-Holmes distillative separation facility using natural gas generated within the facility as the primary energy feedstock to operate the plant. Based on literature review and input from experts in the field of CO_2-EOR, this characterization is believed to be representative of CO_2-EOR state-of-the-art, and is assigned an indicator score of 2.

6.3.3 Results

This section presents the life cycle GHG emissions for LC Stage #3c. Deterministic results are presented for this life cycle stage along with a sensitivity analysis to determine the influence of construction-related activities on total CO_2e emissions. A probabilistic uncertainty analysis was not included because the only operational quantity that was varied was the amount of supercritical carbon dioxide emitted to the atmosphere during EOR operations.

6.3.3.1 Deterministic Greenhouse Gas Emissions

The deterministic results for Life Cycle Stage #3c are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S3c.Summ, which presents the input flows, output flows (products and co-products) and GHG emissions for this stage. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the functional unit. GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are also presented in this sheet.

Table 92 presents the life cycle GHG emissions for Life Cycle Stage #3c in terms of the reference flow for this stage, which is 1 barrel of crude oil ready for transport. This table presents the total emissions of 1) non-biogenic carbon dioxide from operation and construction, 2) biogenic carbon dioxide from operation and construction, 3) methane from operation and construction, 4) nitrous oxide from operation and construction and 5) other GHGs from operation and construction. This last category, other GHGs, captures emissions from GHGs other than carbon dioxide, methane or nitrous oxide, or emissions that are expressed in carbon dioxide equivalents and cannot be differentiated into the primary GHGs. The second column in the table presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the IPCC 2007, IPCC 2001 and IPCC 1996 estimates, respectively.

As indicated in Table 92, EOR operation contributes over 99 percent of the total life cycle GHG emissions for LC Stage #3c. Construction activities (which include installation and de-installation of the infrastructure) are below the threshold of significance for the total life cycle.

Table 92. LC Stage #3c GHG Emissions (per Barrel of Crude Oil Ready for Transport)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/bbl)	Mass of GHG Emitted to Atmosphere (g CO_2e/bbl) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/bbl) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/bbl) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	70,000	70,000	70,000	70,000
Non-biogenic CO_2 – Construction	520	520	520	520
Non-biogenic CO_2 – Subtotal	71,000	71,000	71,000	71,000
Biogenic CO_2 – Operation	0	0	0	0
Biogenic CO_2 – Construction	0	0	0	0
Biogenic CO_2 – Subtotal	0	0	0	0
CH_4 – Operation	80	2,000	1,800	1,700
CH_4 – Construction	1	13	12	11
CH_4 – Subtotal	80	2,000	1,800	1,700
N_2O – Operation	1	150	150	160
N_2O – Construction	0	0	0	0
N_2O – Subtotal	1	150	150	160
Other GHG – Operation		0	0	0
Other GHG – Construction		0	0	0
Other GHG – Subtotal		0	0	0
Operation – Total		72,000	72,000	72,000
Construction – Total		530	530	530
Grand Total		73,000	73,000	73,000

Note: Subtotals and totals may not sum exactly due to rounding.

6.3.3.2 Additional Deterministic Results for LC Stage #3c

In addition to the GHG emissions modeled in support of this study, the LC Stage #3c analysis for CO_2-EOR included characterization of additional parameters, including consumption of electricity, diesel, crude oil, natural gas, construction materials, and other input and output flows. These additional results are presented in Table 93 through Table 97.

Table 93. Energy Consumed in CO_2-EOR Base Case per Barrel of Crude Oil Produced

Energy Products Consumed	Site Eval. & Char.	Construction	Operation	Closure	MVA	Total	Units
Electricity	N/A	N/A	7.33E+01	N/A	N/A	7.33E+01	MJ/bbl crude
Diesel	3.32E-02	3.24E+00	5.47E+00	1.29E+00	6.64E-02	1.01E+01	MJ HHV/bbl crude
Crude Oil	N/A	N/A	N/A	N/A	N/A	N/A	MJ/bbl crude
Natural Gas used at gas processing facility	N/A	N/A	8.92E+02	N/A	N/A	8.92E+02	MJ/bbl crude
Natural gas used in tank battery (heater/treater)	N/A	N/A	2.20E+01	N/A	N/A	2.20E+01	MJ/bbl crude
Total natural gas used per (pattern year)	N/A	N/A	9.14E+02	N/A	N/A	9.14E+02	MJ/bbl crude
Natural Gas Liquids	N/A	N/A	N/A	N/A	N/A	N/A	MJ/bbl crude

Table 94. Mass of CO_2 Geologically Stored per Barrel of Oil Produced in CO_2-EOR Operations

Parameter	Operation	Units
CO_2 Geologically Stored	228	kg CO_2 purchased/bbl crude

Table 95. Summary of Material Demand Associated with CO_2-EOR Activity (All Phases)

Parameter	Value	Unit
Concrete	1.06E-04	metric tonnes concrete/bbl crude
316 Stainless Steel	1.04E-05	metric tonnes 316 stainless steel/bbl crude
Type I Portland Cement	1.89E-04	metric tonnes Type I Portland cement/bbl crude
Fresh Water	7.44E-04	metric tonnes fresh water/bbl crude

Table 96. Direct Emissions of Greenhouse Gasses from Each Phase of CO_2-EOR Operation

Greenhouse Gas	Site Eval. & Char.	Construction	Operation	Closure	MVA	Total	Units
Operations-CO_2	2.2E-03	2.3E-01	5.4E+01	9.0E-02	4.4E-03	5.4E+01	kg/bbl crude
Operations-CH_4	0.0E+00	6.0E-05	5.9E-02	0.0E+00	0.0E+00	5.9E-02	kg/bbl crude
Operations-N_2O	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	kg/bbl crude
Operations-SF_6	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	kg/bbl crude

Table 97. Summary of Energy Products Generated Through CO2-EOR Operations in the Base Case

Energy Products (gross)	Operation	Units
Crude Oil	6,118	MJ HHV/bbl crude
Gas Processing Plant Natural Gas	720	MJ HHV/bbl crude
Tank Battery Natural Gas	100	MJ HHV/bbl crude
Total produced natural gas	820	MJ HHV/bbl crude
Natural Gas Liquids	172	MJ HHV/bbl crude

6.3.3.3 Sensitivity Analysis

To determine the influence of the key variables in Table 89 on the calculated CO_2e emissions, a sensitivity analysis was performed. In the sensitivity analysis, the total CO_2e emission using the IPCC 2007 global warming potentials was calculated for each key variable in Table 89. Table 98 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions. The Absolute Difference for each key variable is also shown, and key variables are listed from highest to lowest based on their Absolute Difference. This same result is presented graphically in the tornado chart presented in Figure 43**.** The only variable that has a significant influence on the total CO_2e emissions is the “Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere”. The other key variables have negligible influences on total CO_2e emissions.

Table 98. Sensitivity Analysis Results for Total CO_2e Emissions for Stage #3c (Using IPCC 2007 GWP) (g CO_2e/bbl of Crude Oil Ready for Transport)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/bbl crude oil)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	71400	74400	3060
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air	kg/kg	0.005	0	0.01	71800	74000	2270
Upstream CH_4 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CH4	kg CH_4/kWh	0.001	0.0009	0.0011	72900	73000	102
Diesel Used per Barrel of Crude Oil Extracted	Dies_used_bbl_x	kg/bbl	0.102	0.0917	0.153	72900	73000	50.2
Steel, 316 Stainless Cold Rolled Used per Barrel of Crude Oil Extracted	Stl_CR316_bbl_x	kg/bbl	0.0104	0.00935	0.0156	72900	72900	33.8
Type I Portland Cement Used per Barrel of Crude Oil Extracted	Cement_Port1_bbl_x	kg/bbl	0.189	0.17	0.283	72900	72900	28.7
Upstream CO_2 Emitted per kg Natural Gas Produced	NatGas_Upstr_CO2	kg CO_2/kg	0.0737	0.0701	0.0811	72900	72900	22
Upstream CO_2 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CO2	kg CO_2/kg	0.718	0.683	0.754	72900	72900	16
Upstream N_2O Emitted per kg Natural Gas Produced	NatGas_Upstr_N2O	kg N_2O/kg	0.00016	0.000152	0.000176	72900	72900	14.2
Upstream N_2O Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_N2O	kg N_2O/kWh	0.00000966	0.00000869	0.0000106	72900	72900	11.7
Concrete, Mixed 5-0 Used per Barrel of Crude Oil Extracted	Concrete_5_0_bbl_x	kg/bbl	0.106	0.0954	0.159	72900	72900	8.82
Upstream CH_4 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CH4	kg CH_4/kg	0.004	0.0038	0.0042	72900	72900	2.22
Upstream CH_4 Emitted per kg Natural Gas Produced	NatGas_Upstr_CH4	kg CH_4/kg	0.000118	0.000112	0.00013	72900	72900	0.881
Upstream N_2O Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_N2O	kg N_2O/kg	0.000013	0.0000123	0.0000136	72900	72900	0.086

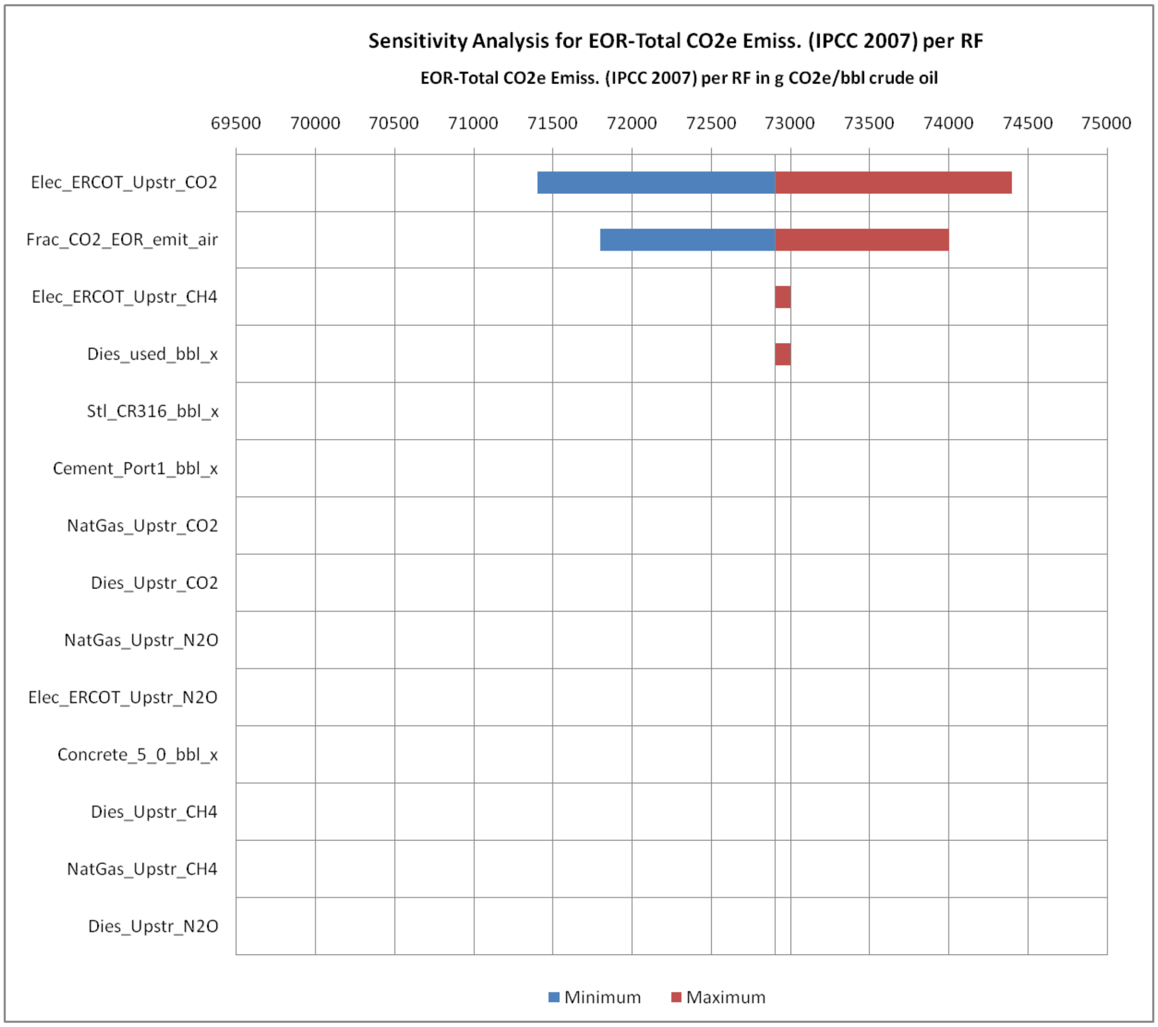


Figure 43. LC Stage #3c Sensitivity Analysis Results for Total CO_2e Emissions (Using IPCC 2007 GWP) (g CO_2e per bbl of Crude Oil Ready for Transport)

6.4 Saline Aquifer Carbon Dioxide Sequestration (LC Stage #3d)

LC Stage #3d includes transport of carbon dioxide from the CBTL facility to an injection well. The boundary ends with the injection of carbon dioxide into a saline geologic aquifer, where it is sequestered indefinitely. Pipeline transport distance for the carbon dioxide prior to injection is 100 miles. Construction of the pipeline required for carbon dioxide transport is included in the LC Stage #3d boundary.

6.4.1 Modeling Approach and Data Sources

Pipeline transport of carbon dioxide for LC Stage #3d relies on the same factors and modeled calculations as pipeline transport of carbon dioxide under LC Stage #3b, with one exception: for LC Stage #3d, the carbon dioxide transport point-to-point length is 100 miles, as compared 775 miles (861 miles accounting for tortuosity) for LC Stage #3d. For additional information regarding pipeline construction and operation in support of carbon dioxide transport, please refer to the discussion for LC Stage #3b (**Section 6.2** of this report).

Following transport to the sequestration site, the carbon dioxide is still under high pressure and in a supercritical state. This pressure is assumed to drive the carbon dioxide underground, into the saline formation for sequestration, without additional pumping requirements at the injection wellhead. After the CO_2 has arrived at the injection site, a loss factor of 0.5 percent is assumed for injection and storage. Table 99 shows the key assumptions that are relevant to saline aquifer carbon dioxide sequestration.

Table 99. Key Assumptions for Saline Aquifer Carbon Dioxide Sequestration

Primary Subject	Assumption	Basis	Source
Pipeline Length	100 miles	Assumed reasonable distance between CBTL facility and sequestration site	Study Value
Carbon Dioxide Loss Rate	0.5%	Performance goal for NETL Carbon Sequestration Technology Roadmap	NETL Carbon Sequestration Technology Roadmap and Program Plan (NETL, 2007a)
Energy Source for Pumping	CBTL Facility	Assumes that CO2 is sufficiently pressurized at CBTL facility and along during pipeline transport, with energy for pressurization modeled as a portion of the total energy requirements for the CBTL	Based on Study Design Basis

6.4.1.1 Key Modeling Variables

The key variables that are relevant specifically to LC Stage #3d are shown in Table 100. For each variable the best estimate is presented, along with the minimum value, maximum value, most likely value and the distribution assumed for the variable. All other pipeline operations key variables, and all pipeline construction key variables, are the same as those discussed for LC Stage #3b. Please refer to **Section 6.2** for additional details.

For most variables in Table 100 where data were not readily available to estimate uncertainty, and/or evaluate a most likely value, the minimum and maximum values were assumed to be a multiple of the best estimate. If the uncertainty is low or moderate, the multiplier was 0.9 for the minimum value (i.e., 10 percent less than the best estimate) and 1.1 for the maximum value (i.e., 10 percent more than the best estimate). If the uncertainty is higher, the multiplier for the minimum value was lower and the multiplier for the maximum value was higher. Professional judgment was used to assess the level of uncertainty for each variable.

Table 100. Key Modeling Variables for Transport and Sequestration of Supercritical CO_2 (LC Stage #3d)

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-CO_2 Pipeline Operation							
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	tonne/tonne	0.005	0	0.01	0.005	Uniform	Assumes that fraction of CO_2 lost can be as low as zero and as high as 1% with a best estimate of 0.5%
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	mi	100	90	110	100	Uniform	Assumes that point-to-point length of pipeline can be 10% higher or 10% lower than best estimate
Tortuosity Factor for Pipeline		0.1	0.05	0.2	0.1	Triangular	Assumes that tortuosity factor for pipeline can be 100% higher or 50% lower than best estimate
Input Parameters-CO_2 Pipeline Construction							
Mass of Pipeline per m	kg/m	183.05	164.75	201.36	183.05	Uniform	Assumes that mass of pipe per m can be 10% higher or 10% lower than best estimate
Fraction of Installation Inputs and Outputs Assumed to Apply to De-Installation		0.1	0.05	0.25	0.1	Triangular	Assumed based on best engineering judgment
Diesel Fuel Used per Mile of Installed Pipeline	L/mi	9,200	8,280	10,120	9,200	Uniform	Assumes that diesel used per mile of installed pipeline can be 10% higher or 10% lower than best estimate
Input Parameters-Upstream GHG Emissions from Secondary Energy Unit Processes							
Upstream CO_2 Emitted per kg Petroleum Diesel Fuel Produced	kg CO_2/kg	0.72	0.68	0.75	0.72	Triangular	Assumed that upstream GHG emissions are -5% to +5% of best estimate
Upstream CH_4 Emitted per kg Petroleum Diesel Fuel Produced	kg CH_4/kg	4.00E-03	3.80E-03	4.20E-03	4.00E-03	Triangular	Assumed that upstream GHG emissions are -5% to +5% of best estimate
Upstream N_2O Emitted per kg Petroleum Diesel Fuel Produced	kg N_2O/kg	1.30E-05	1.23E-05	1.36E-05	1.30E-05	Triangular	Assumed that upstream GHG emissions are -5% to +5% of best estimate

6.4.2 Data Quality Assessment

The results of unit process data quality evaluation for LC Stage #3d are provided in Table 101. A data quality indicator and life cycle significance determination is listed for the saline aquifer operation process. The data for this sub-stage is based primarily on an assumed leakage rate for CO_2 from the geologic sequestration site. Improved data based on measurements should replace this assumption when available. For the current study, the parameter is included in sensitivity analysis.

Table 101. LC Stage #3d Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Lifecycle Significance of Process (%)
1	Saline Aquifer Operation	1,3,1,2,1	0.34

6.4.3 Results

This section presents the life cycle GHG emissions for Life Cycle Stage #3d. The first section presents the deterministic results. The second section presents the range in GHG emissions when variables that are uncertain are allowed to be varied in a probabilistic simulation. The third section presents the influence of each uncertain variable on GHG emissions when the uncertain variables are systematically varied in a sensitivity analysis.

6.4.3.1 Deterministic Greenhouse Gas Emissions

The deterministic results for Stage #3d are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S3b.Summ (when Scenario 2 for Managing Super Critical CO_2 has been chosen in sheet Scen.Control), which presents the input flows, output flows (products and co-products) and GHG emissions for this stage. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the functional unit. GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are also presented in this sheet.

Table 102 presents the life cycle GHG emissions for Life Cycle Stage #3d in terms of the reference flow for this stage, which is 1 tonne of supercritical CO_2 sequestered in a saline aquifer. This table presents the total emissions of 1) non-biogenic carbon dioxide from operation and construction, 2) biogenic carbon dioxide from operation and construction, 3) methane from operation and construction, 4) nitrous oxide from operation and construction and 5) other GHGs from operation and construction. This last category, other GHGs, captures emissions from GHGs other than carbon dioxide, methane or nitrous oxide, or emissions that are expressed in carbon dioxide equivalents and cannot be differentiated into the primary GHGs. The second column in the table presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the IPCC 2007, IPCC 2001 and IPCC 1996 estimates, respectively.

As indicated in Table 102, a majority of carbon dioxide emissions result from operation of the carbon dioxide pipeline and sequestration site from fugitive CO_2 emissions. As noted

previously, operation of the pipeline-sequestration system does not require the combustion of fossil fuels or the consumption of electricity to run pumps or other facilities (the carbon dioxide is pressurized at the CBTL facility). Construction related carbon dioxide emissions amount to about 4.1 percent of total CO_2e emissions. Emissions of methane and nitrous oxide occur only as a result of construction, and amount to about 4 percent of total construction CO_2e emissions, and less than 0.5 percent of total CO_2e emissions.

Table 102. LC Stage #3d GHG Emissions (per Tonne of Supercritical CO_2 Sequestered in a Saline Aquifer)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/tonne CO_2)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne CO_2) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne CO_2) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/tonne CO_2) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	6,100	6,100	6,100	6,100
Non-biogenic CO_2 – Construction	250	250	250	250
Non-biogenic CO_2 – Subtotal*	6,300	6,300	6,300	6,300
Biogenic CO_2 – Operation	0	0	0	0
Biogenic CO_2 – Construction	0	0	0	0
Biogenic CO_2 – Subtotal	0	0	0	0
CH_4 – Operation	0	0	0	0
CH_4 – Construction	0	7	6	6
CH_4 – Subtotal	0	7	6	6
N_2O – Operation	0	0	0	0
N_2O – Construction	0	4	4	4
N_2O – Subtotal	0	4	4	4
Other GHG – Operation		0	0	0
Other GHG – Construction		0	0	0
Other GHG – Subtotal		0	0	0
Operation – Total		6,100	6,100	6,100
Construction– Total		260	260	260
Grand Total*		6,400	6,400	6,400

Note: Subtotals and totals may not sum exactly due to rounding.

6.4.3.2 Probabilistic Uncertainty Analysis

In an attempt to quantify the influence of uncertainty in the key variables presented in Table 100 on the calculated GHG emissions, probabilistic simulations were performed. In this evaluation, probabilistic simulations were performed for total life cycle GHG emissions using the IPCC 2007 global warming potentials. CO_2 equivalent emissions were calculated relative to the stage reference flow of 1 tonne of supercritical CO_2 injected into saline aquifer. Table 103 presents the statistics for the CO_2e emissions developed from the simulations. Figure 44 presents the cumulative distribution and probability density function for CO_2 equivalent emissions relative to the LC Stage #3d reference flow. In Figure 44, the vertical scale on the left is for the probability density function and the vertical scale on the right is for the cumulative distribution.

The CO_2 equivalent emissions relative to the reference flow range from 1.1 to 12 kg CO_2e/tonne CO_2, with a median value of 6.5 kg CO_2e/tonne CO_2, and a mean of 6.4 kg CO_2e/tonne CO_2. Eighty percent of the distribution lies between 2.3 and 10 kg CO_2e/tonne CO_2 and the middle fifty percent of the distribution lies between 3.8 and 8.9 kg CO_2e/tonne CO_2. The distribution of

total CO_2e emissions in Figure 44 appears to closely approximate a uniform distribution. This is probably because, as discussed in the next section, one variable (the fraction of CO_2 in the pipeline and sequestered that is lost to the atmosphere) determines almost all the CO_2e emissions and this variable is uniformly distributed.

Table 103. LC Stage #3d: Probabilistic Uncertainty Analysis; Statistics for CO_2e Emissions

Statistical Parameter	Mass of GHG Emitted to Atmosphere (kg CO_2e/tonne CO_2) (IPCC 2007 GWP)
Minimum	1.1
10%	2.3
25%	3.8
Median (50%)	6.5
75%	8.9
90%	10
Maximum	12
Mean	6.4
Mode	9.8
Stand. Deviation	0.57

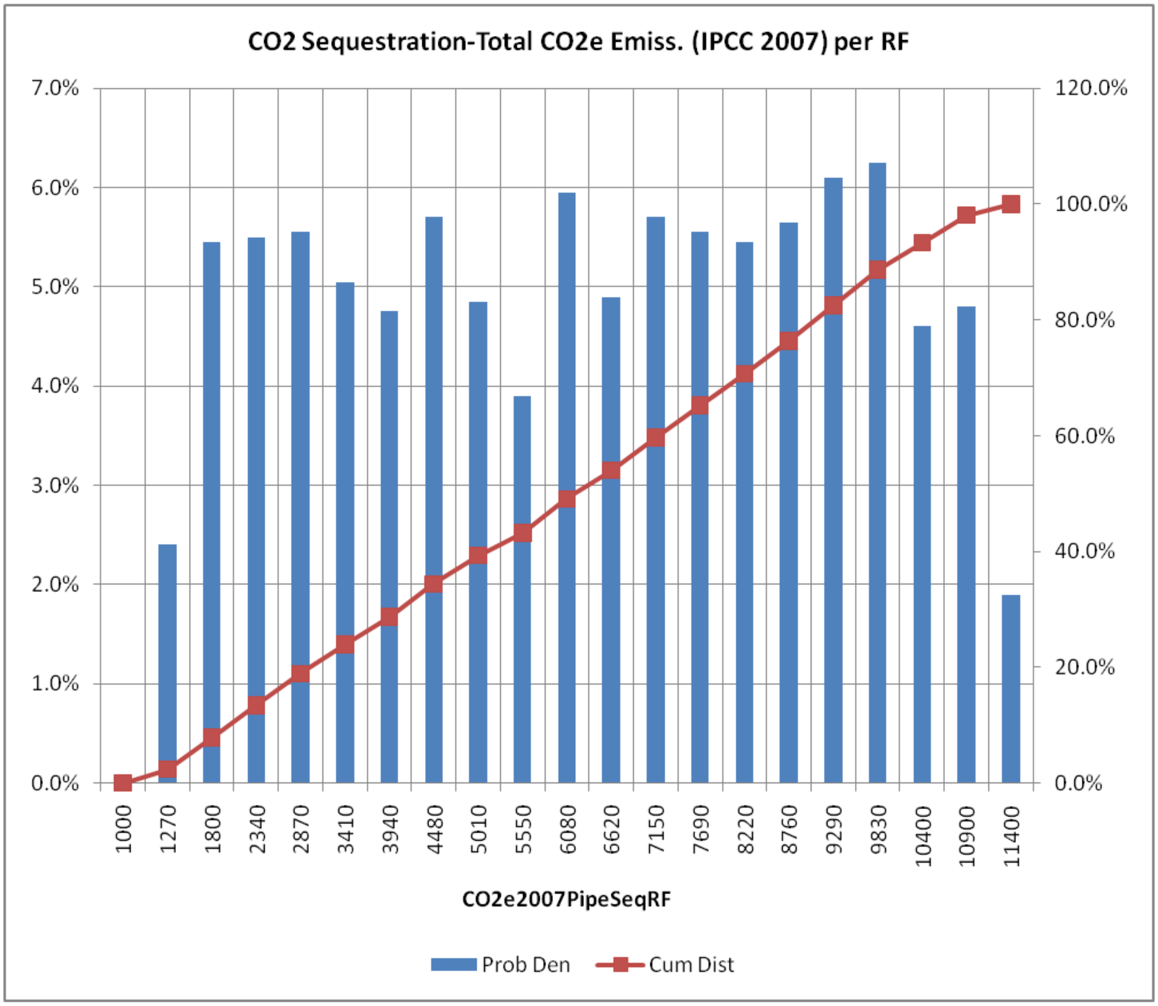


Figure 44. LC Stage #3d Probability Density Function and Cumulative Distribution of CO_2e Emissions (Using IPCC 2007 GWP) (per Tonne CO_2 Sequestered in a Saline Aquifer)

6.4.3.3 Sensitivity Analysis

In the sensitivity analysis, the total CO_2e emission using the IPCC 2007 global warming potentials was calculated for each key variable. Table 104 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions. The Absolute Difference for each key variable is also shown, and key variables are listed from highest to lowest based on their Absolute Difference. Figure 45 presents the same results graphically in a tornado chart.

One variable, the fraction of CO_2 captured at the CBTL facility that is lost to the atmosphere during pipeline transport, injection, and storage at the sequestration site, has an overwhelming influence on the calculated CO_2e emissions. The remaining five variables have essentially no influence on the calculated CO_2e emissions.

Table 104. Sensitivity Analysis Results (Using IPCC 2007 GWP) (g CO_2e/Tonne Supercritical CO_2 Sequestered in a Saline Aquifer)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/tonne CO_2)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS	tonne/tonne	0.005	0	0.01	1300	11400	10100
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi	mi	100	90	110	6210	6470	263
Tortuosity Factor for Pipeline	Pipe_tort		0.1	0.05	0.2	6270	6500	233
Mass of Pipeline per m	Pipe_Mass_Per_m	kg/m	183	165	201	6310	6360	47.5
Diesel Fuel Used per Mile of Installed Pipeline	Dies_Used_mi	L/mi	9200	8280	10100	6330	6340	4.81
Fraction of Installation Inputs and Outputs Assumed to Apply to De-Installation	DeIn_Frac		0.1	0.05	0.25	6340	6340	4.37
Upstream CO_2 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CO2	kg CO_2/kg	0.718	0.683	0.754	6340	6340	0.435
Upstream CH_4 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CH4	kg CH_4/kg	0.004	0.0038	0.0042	6340	6340	0.0605
Upstream N_2O Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_N2O	kg N_2O/kg	0.000013	0.0000123	0.0000136	6340	6340	0.00234

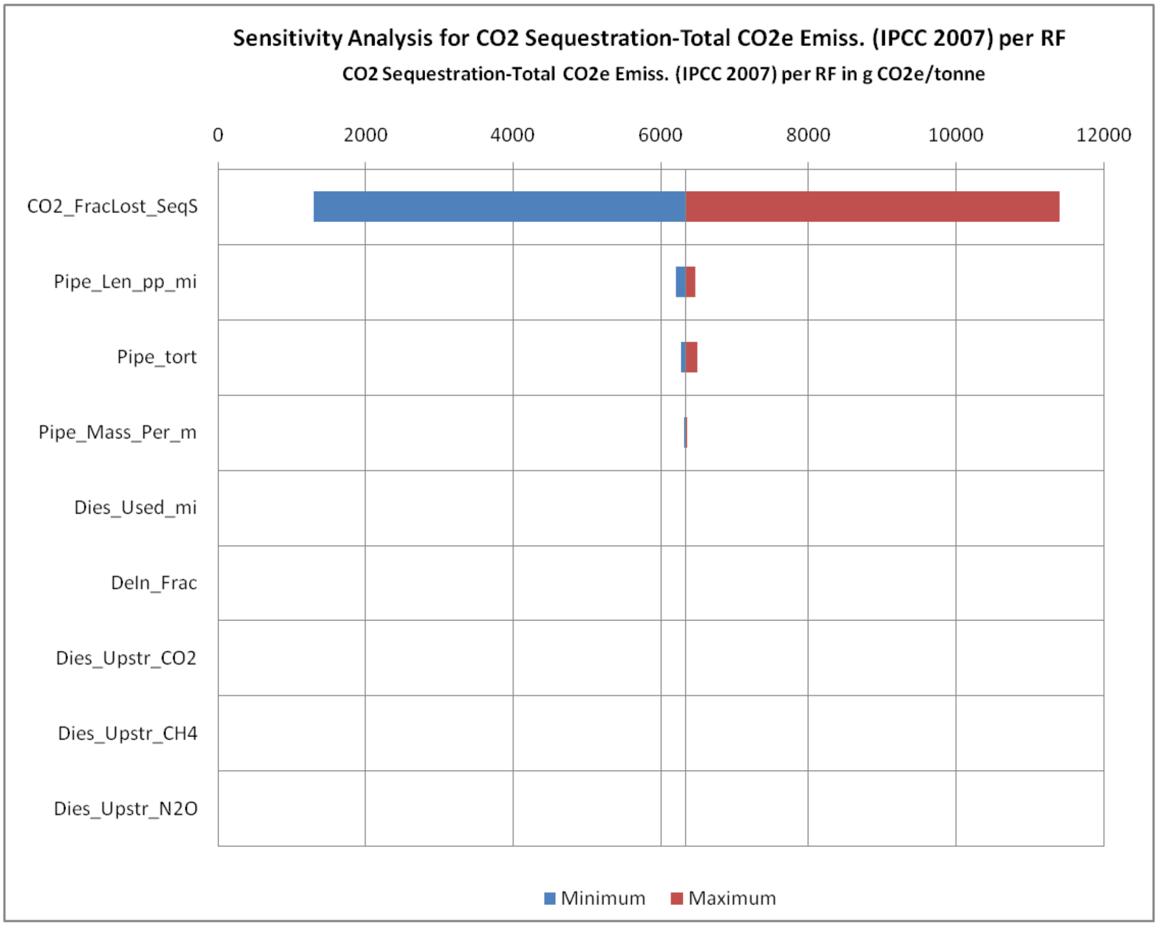


Figure 45. LC Stage #3d Sensitivity Analysis Results (Using IPCC 2007 GWP) (g CO_2e per Tonne Supercritical CO_2 Sequestered in a Saline Aquifer)

7.0 LC STAGE #4: PRODUCT TRANSPORT & REFUELING

LC Stage #4 includes pipeline transport of F-T jet fuel from the CBTL facility to a petroleum refinery and blending with petroleum based conventional jet fuel (LC Stage #4a), upstream emissions associated with the production and transport of conventional (petroleum-based) jet fuel (LC Stage #4b), and transport of blended jet fuel either to Chicago O'Hare Airport, or to a combination of Chicago O'Hare Airport and smaller regional airports, based on one of two modeling options (LC Stage #4c).

7.1 LC Stage #4a: Transport to Refinery and Blending

LC Stage #4a includes pipeline transport of F-T jet fuel from the CBTL facility under LC Stage #3a to a petroleum refinery. At the refinery, the F-T jet fuel is blended with conventional, petroleum-based jet fuel. Blending operations are accounted for within LC Stage #4a, however, upstream emissions associated with the petroleum jet fuel are accounted for separately, under LC Stage #4b.

7.1.1 Modeling Approach and Data Sources

The petroleum refinery for this evaluation is assumed to be the refinery in Wood River, Illinois. Emissions associated with the acquisition of crude oil, transport of crude oil and production of conventional jet fuel from the crude oil at the petroleum refinery are accounted for in LC Stage #4b. The pipeline used for transporting the F-T jet fuel to Wood River is assumed to be a pre-existing pipeline used to transport petroleum products. However, it is assumed that an approximately 20 mile length of pipeline will need to be constructed to connect the CBTL facility to the petroleum pipeline.

Table 105. Key Assumptions for Jet Fuel Transport and Blending

Primary Subject	Assumption	Basis	Source
Approximate point to point distance from CBTL to Wood River Refinery	225 miles	Estimated distance between CBTL facility and Wood River Refinery	Working Group Engineering Calculation
Location of Blending	Wood River Refinery	This is an existing and major regional refinery that could likely support blending	Study Value
Length of constructed pipeline segment to regional pipeline	20 miles	Feasible distance between CBTL facility and existing regional pipelines	Working Group Engineering Judgment
Blending rate for F-T/conventional jet fuel	50%-50% blend by volume	Compliance with existing regulations requiring no greater than 50% blend of alternative fuels in jet fuel	Study Value
Constructed Facilities	20-mile pipeline from CBTL facility connecting to a regional petroleum pipeline that transports products to Wood River Refinery	Regional pipeline is existing	Working Group Engineering Calculation
Conventional jet fuel production and transport emissions	Incorporated into LC Stage #4	Scope of study limited to the F-T jet fuel fraction until LC Stage #4	Study Value

7.1.1.1 Life Cycle Inventory Model

Figure 46 shows the individual processes that were modeled for LC Stage #4a. As shown, transport of F-T jet fuel to the Wood River Refinery and blending were modeled separately from upstream conventional petroleum jet fuel emissions, and from transport of blended jet fuel. Additional discussion of modeled steps is provided below.

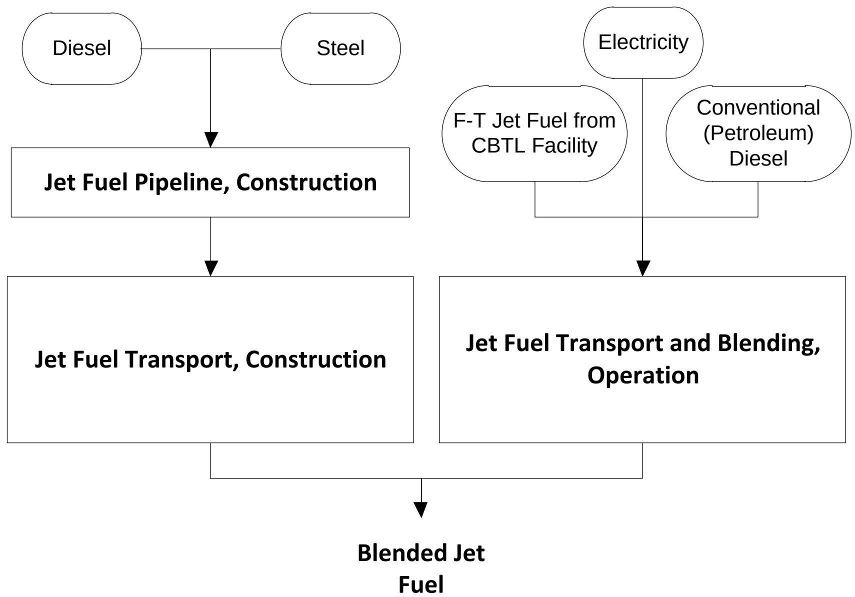


Figure 46. Process for Jet Fuel Transport and Blending

Transport of F-T jet fuel under LC Stage #4a includes operation of a pipeline from the CBTL facility to the Wood River refinery in Illinois, a point to point distance of 225 miles. The model assumes that all facilities needed for the pipeline transport of F-T jet fuel currently exist, except for a 20-mile fuel transport pipeline segment that connects the CBTL facility (LC Stage #3a) to a regional pipeline. Construction related emissions are included for this 20-mile pipeline segment. However, the remaining length of pipeline is assumed to be existing. Materials associated with construction of the pipeline are assumed to be steel and diesel.

Electrical powered pumps are used to move the fuels through the pipeline, and energy intensity consistent with petroleum pipeline transport is assumed: 2.77e-5 kWh/kg-mi, according to Franklin and Associates, Inc. as reported in an Oregon Department of Environmental Quality report (Oregon DEQ, 2004). The energy intensity number will differ slightly due to the varying densities of the fuels as the energy consumption values are based on the mass of flow through the pipe. A mass efficiency of 100 percent is assumed for pipeline transport – that is, the analysis assumes zero loss of fuel during transport. The emissions associated with the electricity used for pipeline transport is modeled using the regional power grid mix.

Blending of the F-T jet fuel with 50 percent conventional jet fuel (by volume) under LC Stage #4 includes blending procedures completed at the Wood River refinery, located in Illinois. Blending would result in a 1:1 mixture (by volume) of F-T jet fuel and conventional jet fuel.

Blending operations are assumed to require electricity for the operation of pumps. An electricity consumption rate of 3.89e-4 kWh/kg is assumed, for the pumping of fuel through the blending tank.

All facilities required for the blending of F-T jet fuel with 50 percent conventional jet fuel are assumed to exist. Therefore, construction material and energy requirements and associated emissions are not considered within this segment of the model.

Emissions associated with conventional jet fuel production upstream of the blending facility are accounted for in LC Stage #4b.

LC Stage #4a is implemented in the F-T Jet Fuel Spreadsheet Model through a number of sheets. For operations, all the input flows, output flows and GHG emissions are determined in sheet S4a.UP.O.JFTranOp. The input flows are:

- F-T jet fuel leaving CBTL
- conventional jet fuel entering blending tank
- electricity

The output flows are:

- blended jet fuel leaving blending tank

The GHG emissions are CO_2 from non-biogenic sources, CO_2 from biogenic sources (zero for this stage), CH_4 and N_2O.

The sheet includes additional flows to facilitate mass balance calculations. For jet fuel, additional flows include "jet fuel emitted to air (lost in transport) per kg of blended jet fuel delivered to aircraft". For GHGs, additional flows include "CO_2 to air from combustion", "CH_4 to air from combustion," and "N_2O to air from combustion". These latter variables are all zero for this stage.

Many of these flows are calculated with equations that have adjustable parameters or variables. A number of these variables are specified as random variables with an associated probability distribution. Thus, many of the flows are random variables. The equations used to calculate the various flows are presented in detail in sheets S4a.UP.O.JFTranOp and S4.UP.O.JFTranOp within the F-T Jet Fuel Spreadsheet Model. The variables specified as random variables are presented in the next section.

For construction, all the input flows, output flows and GHG emissions are determined in sheet S4a.UP.C.JFTranCon. This sheet, in turn, references information in sheets S4.UP.C.JFTranCon and S4.UP.C.Pipe. The input flows for construction in this stage are:

- diesel fuel
- steel, pipe welded, BF (85% recovery rate)

The only output flow for construction is a constructed pipe connecting the CBTL to a pipe for transporting petroleum fuel.

The GHG emissions are CO_2 from non-biogenic sources, CO_2 from biogenic sources (zero for this stage), CH_4 and N_2O.

The sheet includes the following additional flows to facilitate mass balance calculations for GHGs: “CO_2 to air from combustion”, “CH_4 to air from combustion,”, and “N_2O to air from combustion”. These flows, which result from the use of diesel fuel during installation and de-installation of the pipeline, are used to generate the total CO_2, CH_4 and N_2O emitted to the atmosphere for construction activities in this stage.

All of the input flows are random variables since they are specified through equations that have random variables with an associated distribution. The GHG emissions result from the combustion of diesel fuel and since this flow is a random variable, the GHG emissions are also random variables. The equations used to calculate the GHG emissions are presented in detail in sheets S4.UP.C.JFTranCon and S4.UP.C.Pipe within the F-T Jet Fuel Spreadsheet Model. The variables specified as random variables are presented in the next section.

7.1.1.2 Key Modeling Variables

The key variables with respect to the emissions of GHGs during the transport of F-T jet fuel to the blending facility, and jet fuel blending, are presented in Table 106. For each variable the best estimate is presented, along with the minimum value, maximum value, most likely value and the distribution assumed for the variable.

For most of the variables in Table 106, data were not readily available to estimate uncertainty, and/or to evaluate a most likely value. For these variables, the minimum and maximum values were assumed to be a multiple of the best estimate. If the uncertainty is low or moderate, the multiplier was 0.9 for the minimum value (i.e., 10 percent less than the best estimate) and 1.1 for the maximum value (i.e., 10 percent more than the best estimate). If the uncertainty is higher, the multiplier for the minimum value was lower and the multiplier for the maximum value was higher. Professional judgment was used to assess the level of uncertainty for each variable.

Table 106. Key Variables for LC Stage #4a and Ranges of Selected Values

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-F-T Jet Fuel Transport and Blending Operation							
Fraction Blended Jet Fuel Emitted to Air During Fuel Mixing at Petroleum Refinery	kg/kg blended jet fuel	2.00E-06	1.00E-06	4.00E-06	2.00E-06	Triangular	Assumes that fraction emitted to atmosphere can vary between 50% lower and 100% higher than best estimate
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and Mile Traveled	kWh/kg-mi	2.77E-05	2.49E-05	4.16E-05	2.77E-05	Triangular	Assumes that electricity required can vary between 10% lower and 50% higher than best estimate
Electricity Required to Pump Fuel Into Mixing Tank Per kg of Fuel Pumped	kWh/kg	3.89E-04	3.50E-04	5.84E-04	3.89E-04	Triangular	Assumes that electricity required can vary between 10% lower and 50% higher than best estimate
Point-to-point Distance from CBTL Facility to Petroleum Refinery in Wood River, Ill	mi	225	203	248	225	Uniform	Assumes that distance for existing pipeline can vary between 10% lower and 10% higher than best estimate
Pipeline Tortuosity		0.10	0.05	0.20	0.10	Triangular	Assumes that pipeline tortuosity can vary between 50% lower and 100% higher than best estimate
Input Parameters- F-T Jet Fuel Transport and Blending Construction							
Length of Pipeline from CBTL Facility to Main Jet Fuel Pipeline	mi	20	10	30	20	Uniform	Assumes that distance for new pipeline can vary between 50% lower and 50% higher than best estimate
Mass of Pipeline per m	kg/m	60.24	54.22	66.26	60.24	Triangular	Assumes that mass per unit length can vary between 10% lower and 10% higher than best estimate
Fraction of Installation Inputs and Outputs Assumed to Apply to De-Installation		0.10	0.05	0.25	0.10	Triangular	Assumed based on best engineering judgment
Diesel Fuel Used per Mile of Installed Pipeline	L/mi	9,200	8,280	10,120	9,200	Uniform	Assumes that diesel used per mile of installed pipeline can be 10% higher or 10% lower than best estimate
Steel Plate, BF (85% Recovery Rate) for All Pieces of Equipment	kg/kg blended jet fuel	1.35E-04	1.21E-04	1.48E-04	1.35E-04	Triangular	Assumes that material used can be 10% higher or 10% lower than best estimate

Table 106. Key Variables for LC Stage #4a and Ranges of Selected Values *(Cont'd)*

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters- Upstream Emissions from Secondary Energy Unit Processes							
Upstream CO_2 Emitted per kg Petroleum Diesel Fuel Produced	kg CO_2/kg	0.72	0.68	0.75	0.72	Triangular	Assumed that upstream GHG emissions are -5% to +5% of best estimate
Upstream CH_4 Emitted per kg Petroleum Diesel Fuel Produced	kg CH_4/kg	4.00E-03	3.80E-03	4.20E-03	4.00E-03	Triangular	Assumed that upstream GHG emissions are -5% to +5% of best estimate
Upstream N_2O Emitted per kg Petroleum Diesel Fuel Produced	kg N_2O/kg	1.30E-05	1.23E-05	1.36E-05	1.30E-05	Triangular	Assumed that upstream GHG emissions are -5% to +5% of best estimate
Upstream CO_2 Emitted per kWh SERC Electricity Produced	kg CO_2/kWh	0.76	0.69	0.84	0.76	Triangular	Assumed that upstream GHG emissions are -10% to +10% of best estimate
Upstream CH_4 Emitted per kWh SERC Electricity Produced	kg CH_4/kWh	8.35E-04	7.52E-04	9.19E-04	8.35E-04	Triangular	Assumed that upstream GHG emissions are -10% to +10% of best estimate
Upstream N_2O Emitted per kWh SERC Electricity Produced	kg N_2O/kWh	1.01E-05	9.08E-06	1.11E-05	1.01E-05	Triangular	Assumed that upstream GHG emissions are -10% to +10% of best estimate

7.1.2 Data Quality Assessment

The results of unit process data quality evaluation for LC Stage #4a are provided in Table 107. Data quality indicators and life cycle significance determinations are listed for the construction and operation processes included in the model of this stage. Analysis of the life cycle uncertainty significance of these processes shows that the composite construction process for transport and blending of jet fuel is of very low significance for the jet fuel production life cycle. This result determines that, although DQI scores appear below the quality requirement of 1-2, the data used for the construction processes are acceptable.

Operation of F-T jet fuel transport and blending is above the 0.01 percent threshold of life cycle GHG emissions. Poor completeness quality was scored for data used to define the amount of electricity used in pipeline transport of jet fuel. Therefore the pipeline electricity use is flagged for sensitivity analysis. In addition, poor temporal and geographic quality is noted for the evaporative diesel emissions from a bulk storage tank. Finally, the completeness, temporal representativeness, and geographic representativeness of tanker truck fuel economy data is flagged for sensitivity analysis.

Table 107. LC Stage #4a Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Life Cycle Significance of Process (%)
1	F-T Jet Fuel Transport and Blending, Operation	1,3,2,2,2	0.06%
1	F-T Jet Fuel Transport and Blending, Construction	2,2,3,3,2	0.00%

7.1.3 Results

This section presents the life cycle GHG emissions for LC Stage #4a, including the following components: (1) deterministic results, where deterministic means that the results are based on setting each variable that is uncertain to its best estimate; (2) the range in GHG emissions when variables that are uncertain are allowed to be varied in a probabilistic simulation; and (3) an analysis of the influence of each uncertain variable on GHG emissions when the uncertain variables are systematically varied in a sensitivity analysis.

7.1.3.1 Deterministic Greenhouse Gas Emissions

The deterministic results for LC Stage #4a are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S4a.Summ, which presents the input flows, output flows (products and co-products) and GHG emissions for this stage. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the functional unit. GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are presented in this sheet.

Table 108 presents the life cycle GHG emissions for LC Stage #4a in terms of the reference flow for this stage, which is 1 kg of blended jet fuel delivered to the aircraft fuel tank. The table presents the total emissions of 1) non-biogenic carbon dioxide from operation and construction, 2) biogenic carbon dioxide from operation and construction, 3) methane from operation and construction, 4) nitrous oxide from operation and construction and 5) other GHGs from operation

and construction. This last category, other GHGs, captures emissions from GHGs other than carbon dioxide, methane or nitrous oxide, or emissions that are expressed in carbon dioxide equivalents and cannot be differentiated into the primary GHGs. The second column in the tables presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the IPCC 2007, IPCC 2001 and IPCC 1996 estimates, respectively.

For LC Stage #4a, CO_2 is responsible for over 95 percent of the total CO_2e greenhouse gas emissions. Operational activities are responsible for about 98 percent of the total, with construction making up the remainder.

Table 108. LC Stage #4a GHG Emissions for Transport and Blending of F-T Jet Fuel (per kg of Blended Jet Fuel Delivered to the Aircraft)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/kg Blended Jet Fuel)	Mass of GHG Emitted to Atmosphere (g CO_2e/ kg Blended Jet Fuel) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/ kg Blended Jet Fuel) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/ kg Blended Jet Fuel) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	2.8	2.8	2.8	2.8
Non-biogenic CO_2 – Construction	0.1	0.1	0.1	0.1
Non-biogenic CO_2 – Subtotal	2.9	2.9	2.9	2.9
Biogenic CO_2 – Operation	0.0	0.0	0.0	0.0
Biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Biogenic CO_2 – Subtotal	0.0	0.0	0.0	0.0
CH_4 – Operation	0.00	0.1	0.1	0.1
CH_4 – Construction	0.00	0.0	0.0	0.0
CH_4 – Subtotal	0.00	0.1	0.1	0.1
N_2O – Operation	0.000	0.0	0.0	0.0
N_2O – Construction	0.000	0.0	0.0	0.0
N_2O – Subtotal	0.000	0.0	0.0	0.0
Other GHG – Operation		0.0	0.0	0.0
Other GHG – Construction		0.0	0.0	0.0
Other GHG – Subtotal		0.0	0.0	0.0
Operation – Total		2.9	2.9	2.9
Construction– Total		0.1	0.1	0.1
Grand Total		3.0	3.0	3.0

Note: Subtotals and totals may not sum exactly due to rounding.

7.1.3.2 Probabilistic Uncertainty Analysis

In an attempt to quantify the influence of uncertainty in the key variables presented in Table 106 on the calculated GHG emissions, probabilistic simulations were performed. In this evaluation, probabilistic simulations were performed for total life cycle GHG emissions using the IPCC 2007 global warming potentials. CO_2 equivalent emissions were calculated relative to the stage reference flow of 1 kg of blended jet fuel delivered to the aircraft fuel tank. Table 109 presents the statistics for the CO_2e emissions developed from the simulations. Figure 47 presents the cumulative distribution and probability density function for CO_2 equivalent emissions relative to

the LC Stage #4a reference flow. In Figure 47, the vertical scale on the left is for the probability density function and the vertical scale on the right is for the cumulative distribution.

The CO_2 equivalent emissions relative to the reference flow range from 2.4 to 5.1 g CO_2e/kg blended jet fuel with a median value of 3.4 g CO_2e/ kg blended jet fuel, a mean of 3.5 g CO_2e/ kg blended jet fuel and a standard deviation of 0.45 g CO_2e/ kg blended jet fuel. Eighty percent of the distribution lies between 2.9 and 4.1 g CO_2e/ kg blended jet fuel and the middle fifty percent of the distribution lies between 3.1 and 3.8 g CO_2e/ kg blended jet fuel.

Table 109. LC Stage #4a: Probabilistic Uncertainty Analysis; Statistics for CO_2e Emissions

Statistical Parameter	Mass of GHG Emitted to Atmosphere (g CO_2e/kg blended jet fuel) (IPCC 2007 GWP)
Minimum	2.4
10%	2.9
25%	3.1
Median (50%)	3.4
75%	3.8
90%	4.1
Maximum	5.1
Mean	3.5
Mode	3.1
Stand. Deviation	0.45

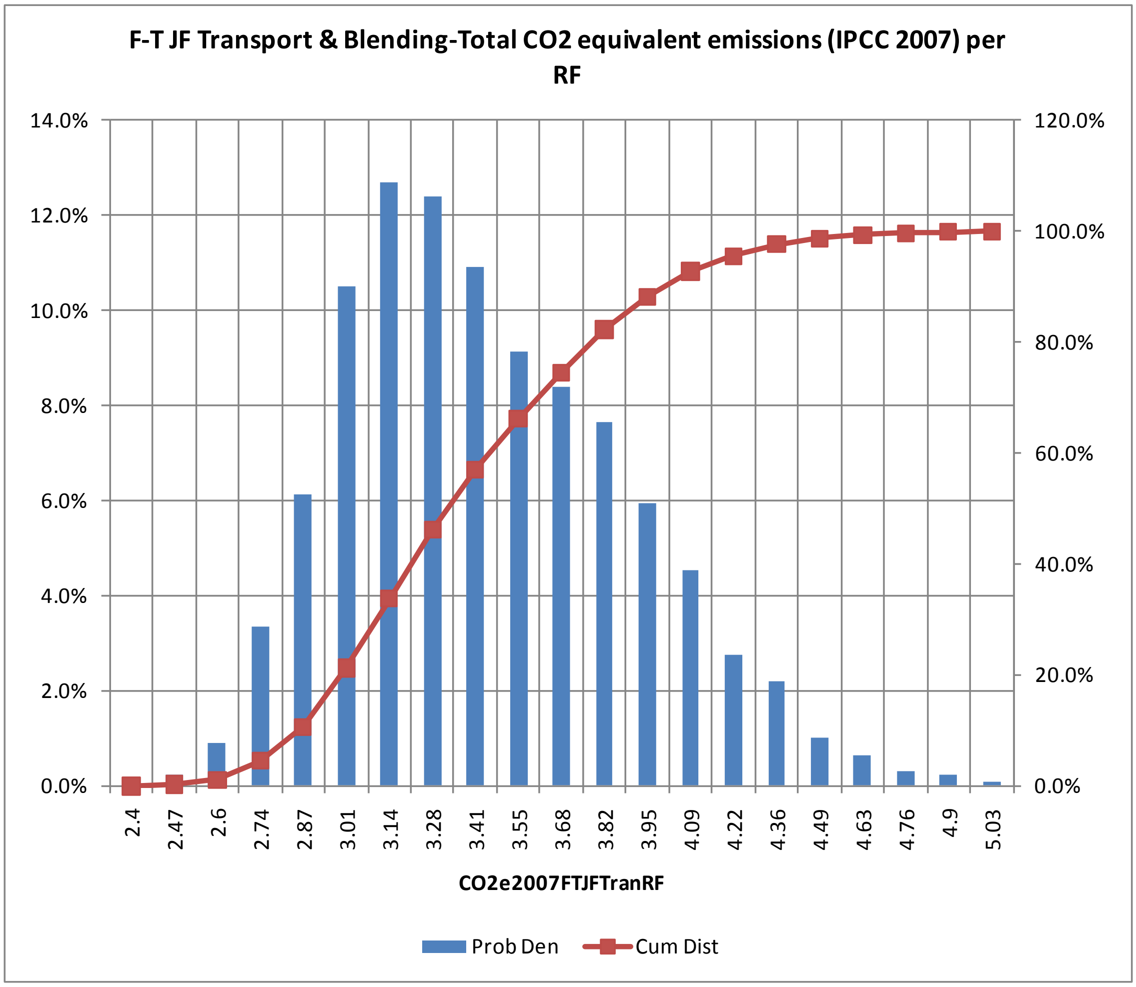


Figure 47. LC Stage #4a Probability Density Function and Cumulative Distribution of CO_2e Emissions (Using IPCC 2007 GWP) (per kg of Blended Jet Fuel Delivered to the Aircraft)

7.1.3.3 Sensitivity Analysis

In the sensitivity analysis, the total CO_2e emission using the IPCC 2007 global warming potentials was calculated for each key variable. Table 110 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions. The absolute difference for each key variable is also shown in the table, and key variables are listed from highest to lowest based on their absolute difference. The same results are presented graphically in Figure 48, which is a tornado chart.

For LC Stage #4a, one variable, the “Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and Mile Traveled”, has the most influence on the calculated CO_2e emissions. Five other variables, “Upstream CO_2 Emitted per kWh SERC Electricity Produced”, “Point-to-point Distance from Petroleum Refinery in Wood River, Ill to O'Hare Airport”, “Pipeline Tortuosity”, and “Electricity Required to Pump Fuel Into Mixing Tank Per kg of Fuel Pumped”, also influence the calculated CO_2e emissions, but to a lesser extent. The remaining variables have little influence on the calculated CO_2e emissions.

Table 110. Sensitivity Analysis Results for Jet Fuel Transport (Using IPCC 2007 GWP) (g CO_2e/kg Blended Jet Fuel Delivered to the Aircraft)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/tonne CO_2)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and Mile Traveled	Elec_Pipe_kg_mi	kWh/kg-mi	2.77E-05	2.49E-05	4.16E-05	2.74	4.31	1.58
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	2.72	3.28	0.569
Point-to-point Distance from CBTL Facility to Petroleum Refinery in Wood River, Ill	CBTL_Ref_Dis1_mi	mi	225	203	248	2.74	3.26	0.525
Pipeline Tortuosity	Pipe_Tort1		0.1	0.05	0.2	2.86	3.33	0.467
Electricity Required to Pump Fuel Into Mixing Tank Per kg of Fuel Pumped	Elec_Tank_kg	kWh/kg	3.89E-04	3.50E-04	5.84E-04	2.97	3.15	0.184
Length of Pipeline from CBTL Facility to Main Jet Fuel Pipeline	Pipe_Len1_mi	mi	20	10	30	2.97	3.03	0.0672
Upstream CH_4 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CH4	kg CH_4/kWh	8.35E-04	7.52E-04	9.19E-04	2.99	3.01	0.0156
Mass of Pipeline per m	Pipe_Mass_Per_m	kg/m	60.2	54.2	66.3	2.99	3	0.0103
Diesel Fuel Used per Mile of Installed Pipeline	Dies_Used_mi	L/mi	9200	8280	10100	3	3	3.17E-03
Fraction of Installation Inputs and Outputs Assumed to Apply to De-Installation	DeIn_Frac		0.1	0.05	0.25	3	3	2.88E-03
Upstream N_2O Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_N2O	kg N_2O/kWh	1.01E-05	9.08E-06	1.11E-05	3	3	2.24E-03
Upstream CO_2 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CO2	kg CO_2/kg	0.718	0.683	0.754	3	3	2.86E-04
Upstream CH_4 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CH4	kg CH_4/kg	4.00E-03	3.80E-03	4.20E-03	3	3	3.98E-05
Fraction Blended Jet Fuel Emitted to Air During Fuel Mixing at Petroleum Refinery	BlendJF_Frac_Emit_Ref	kg/kg blended jet fuel	2.00E-06	1.00E-06	4.00E-06	3	3	9.00E-06
Upstream N_2O Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_N2O	kg N_2O/kg	1.30E-05	1.23E-05	1.36E-05	3	3	1.54E-06

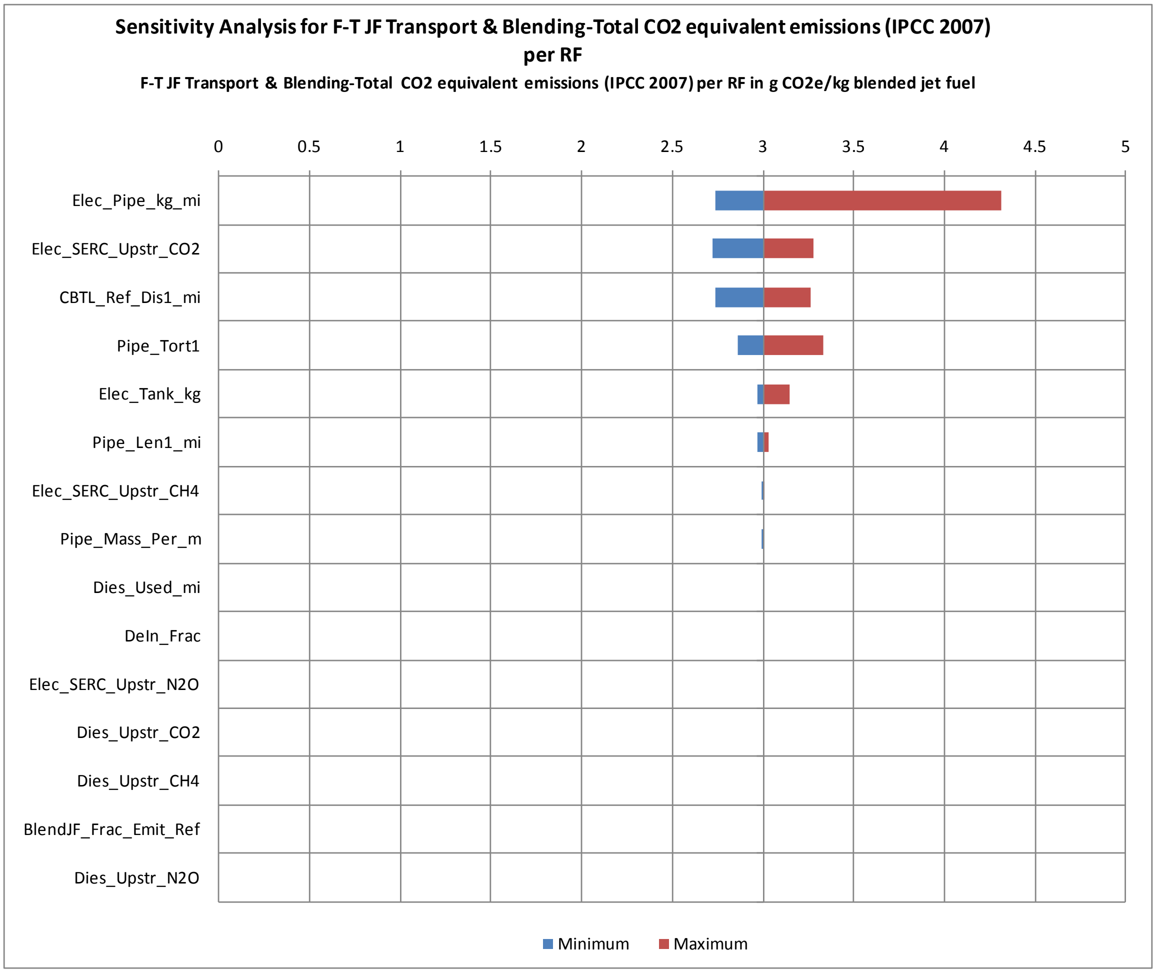


Figure 48. Sensitivity Analysis Results for LC Stage #4a Jet Fuel Transport (Using IPCC 2007 GWP; g CO_2e per kg Blended Jet Fuel Delivered to the Aircraft)

7.2 Life Cycle Stage #4b: Upstream Emissions of Petroleum Jet Fuel

In LC Stage #4a, F-T jet fuel is blended with conventional jet fuel, but the upstream GHG emissions associated with the production of conventional jet fuel are not included in LC Stage #4a. LC Stage #4b includes only the upstream GHG emissions from the production of conventional jet fuel. These GHG emissions are considerable relative to the GHG emissions in LC Stage #4a and #4c, so these GHG emissions are reported separately in this stage to allow their influence on the overall life cycle analysis to be assessed.

7.2.1 Modeling Approach and Data Sources

LC Stages #1a through #4a document the GHG emissions associated with the production and transport of F-T jet fuel. In LC Stage #4a, conventional petroleum jet fuel is blended, in equal proportions, with the F-T jet fuel, and the resulting blended jet fuel is tracked through the remainder of the F-T Jet Fuel Spreadsheet Model.

Because conventional jet fuel is introduced into the system in LC Stage #4, upstream emissions from extraction, transport and refining of crude oil are incorporated into the GHG emissions

result for LC Stage #4. The magnitude of these emissions is much larger than emissions from F-T jet fuel blending and transport, as a comparison with the life cycle GHG emissions from LC Stages #4a and #4c demonstrates. To allow such a demonstration, the upstream GHG emissions associated with the production of conventional jet fuel are calculated and presented in a separate stage, LC Stage #4b.

Upstream emissions estimates for the production of petroleum jet fuel were based on life cycle GHG emissions estimates provided in NETL (2009). These are incorporated into the F-T Jet Fuel Spreadsheet Model as a secondary unit process (see worksheet Sec.UP.All of the F-T Jet Fuel Spreadsheet Model), and include carbon dioxide, methane, and nitrous oxide emissions associated with crude oil extraction, transport to a refinery, and refining into jet fuel.

7.2.1.1 Life Cycle Inventory Model

As discussed above, LC Stage #4b is broken out from the remainder of LC Stage #4 to clearly document the upstream GHG emissions associated with the production of conventional jet fuel. LC Stage #4b is shown conceptually in Figure 49. In the F-T Jet Fuel Spreadsheet Model, there is no input flows or output flows, as flows of conventional jet fuel and blended jet fuel are accounted for in LC Stages #4a and #4c. The only flows are upstream GHG emissions from the production of conventional jet fuel.

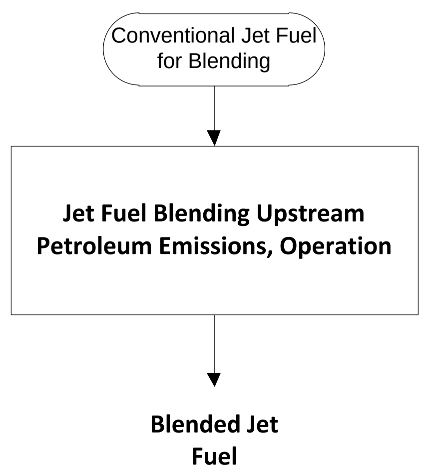


Figure 49. Process for Petroleum Jet Fuel Upstream Emissions

7.2.1.2 Key Modeling Variables

The key variables with respect to the upstream GHG emissions for petroleum jet fuel production are presented in Table 111. There are only three variables in Table 111, the life cycle upstream emissions associated with conventional jet fuel for CO_2, CH_4 and N_2O. As discussed in Section 2.4, these upstream emissions are assumed to be characterized by triangular distributions with minimum values that are 5 percent less than the best estimate in NETL (2009) and maximum values that are 5 percent less than the best estimate.

Table 111. Key Variables for LC Stage #4b and Ranges of Selected Values

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-Jet Fuel Blending and Transport Operation							
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	kg CO_2/kg	0.48	0.45	0.5	0.48	Triangular	Assumed that upstream GHG emissions are -5% to +5% of best estimate
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	kg CH_4/kg	3.61E-03	3.43E-03	3.79E-03	3.61E-03	Triangular	Assumed that upstream GHG emissions are -5% to +5% of best estimate
Upstream N_2O Emitted per kg Conventional Jet Fuel Produced	kg N_2O/kg	5.49E-05	5.21E-05	5.76E-05	5.49E-05	Triangular	Assumed that upstream GHG emissions are -5% to +5% of best estimate

7.2.2 Data Quality Assessment

The results of unit process data quality evaluation for LC Stage #4b are provided in Table 112. Data quality indicators and life cycle significance determinations are listed for the construction and operation processes included in the model of this stage.

The operation process for production of conventional jet fuel is well above the significance threshold for the jet fuel production life cycle. The process is also of sufficient quality for the study.

Table 112. LC Stage #4 Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Life Cycle Significance of Process (%)
1	Jet Fuel Transport, Construction	2,2,2,2,2	6.51%

7.2.3 Results

This section presents the life cycle GHG emissions for LC Stage #4b, including the following components: (1) deterministic results, where deterministic means that the results are based on setting each variable that is uncertain to its best estimate; (2) the range in GHG emissions when variables that are uncertain are allowed to be varied in a probabilistic simulation; and (3) an analysis of the influence of each uncertain variable on GHG emissions when the uncertain variables are systematically varied in a sensitivity analysis.

7.2.3.1 Deterministic Greenhouse Gas Emissions

The deterministic results for LC Stage #4b are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S4b.Summ, which presents the input flows, output flows (products and co-products) and GHG emissions for this stage. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the functional unit. GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are presented in this sheet.

Table 113 presents the life cycle greenhouse gas emissions for LC Stage #4b in terms of the reference flow for this stage, which is 1 kg of blended jet fuel delivered to the aircraft fuel tank. This table presents the total emissions of 1) non-biogenic carbon dioxide from operation and construction, 2) biogenic carbon dioxide from operation and construction, 3) methane from operation and construction, 4) nitrous oxide from operation and construction and 5) other greenhouse gases from operation and construction. This last category, other greenhouse gases, captures emissions from greenhouse gases other than carbon dioxide, methane or nitrous oxide, or emissions that are expressed in carbon dioxide equivalents and cannot be differentiated into the primary greenhouse gases. The second column in the tables presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the IPCC 2007, IPCC 2001 and IPCC 1996 estimates, respectively.

For Stage #4b, CO_2 is responsible for over 82 percent of the total CO_2e greenhouse gas emissions, while CH_4 is responsible for 15 percent and N_2O is responsible for the remainder.

Table 113. LC Stage #4b Upstream GHG Emissions from Production of Conventional Jet Fuel (per kg of Blended Jet Fuel Delivered to the Aircraft)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/kg Blended Jet Fuel)	Mass of GHG Emitted to Atmosphere (g CO_2e/ kg Blended Jet Fuel) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/ kg Blended Jet Fuel) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/ kg Blended Jet Fuel) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	250.0	250.0	250.0	250.0
Non-biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Non-biogenic CO_2 – Subtotal	250.0	250.0	250.0	250.0
Biogenic CO_2 – Operation	0.0	0.0	0.0	0.0
Biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Biogenic CO_2 – Subtotal	0.0	0.0	0.0	0.0
CH_4 – Operation	1.90	47.0	43.0	39.0
CH_4 – Construction	0.00	0.0	0.0	0.0
CH_4 – Subtotal	1.90	47.0	43.0	39.0
N_2O – Operation	0.028	8.5	8.4	8.8
N_2O – Construction	0.000	0.0	0.0	0.0
N_2O – Subtotal	0.028	8.5	8.4	8.8
Other GHG – Operation		0.0	0.0	0.0
Other GHG – Construction		0.0	0.0	0.0
Other GHG – Subtotal		0.0	0.0	0.0
Operation – Total		310.0	310.0	310.0
Construction– Total		0.0	0.0	0.0
Grand Total		310.0	310.0	310.0

Note: Subtotals and totals may not sum exactly due to rounding.

7.2.3.2 Probabilistic Uncertainty Analysis

In an attempt to quantify the influence of uncertainty in the key variables presented in Table 111 on the calculated greenhouse gas emissions, probabilistic simulations were performed. In this evaluation, probabilistic simulations were performed for total life cycle greenhouse gas emissions using the IPCC 2007 global warming potentials. CO_2 equivalent emissions were calculated relative to the stage reference flow of 1 kg of blended jet fuel delivered to the aircraft fuel tank. Table 114 presents the statistics for the CO_2e emissions developed from the simulations. Figure 50 presents the cumulative distribution and probability density function for CO_2 equivalent emissions relative to the LC Stage #4b reference flow. In Figure 50, the vertical scale on the left is for the probability density function and the vertical scale on the right is for the cumulative distribution. The probability density function in Figure 50 has a distinct triangular shape, reflecting the fact that the three variables making up this distribution are drawn from triangular distributions.

The CO_2 equivalent emissions relative to the reference flow range from 290 to 316 g CO_2e/kg blended jet fuel with a median value of 302 g CO_2e/ kg blended jet fuel, a mean of 302 g CO_2e/ kg blended jet fuel and a standard deviation of 5 g CO_2e/ kg blended jet fuel. Eighty percent of the distribution lies between 295 and 309 g CO_2e/ kg blended jet fuel and the middle fifty percent of the distribution lies between 299 and 306 g CO_2e/ kg blended jet fuel.

Table 114. LC Stage #4b: Probabilistic Uncertainty Analysis; Statistics for CO_2e Emissions

Statistical Parameter	Mass of GHG Emitted to Atmosphere (g CO_2e/kg blended jet fuel) (IPCC 2007 GWP)
Minimum	290
10%	295
25%	299
Median (50%)	302
75%	306
90%	309
Maximum	316
Mean	302
Mode	302
Stand. Deviation	5.06

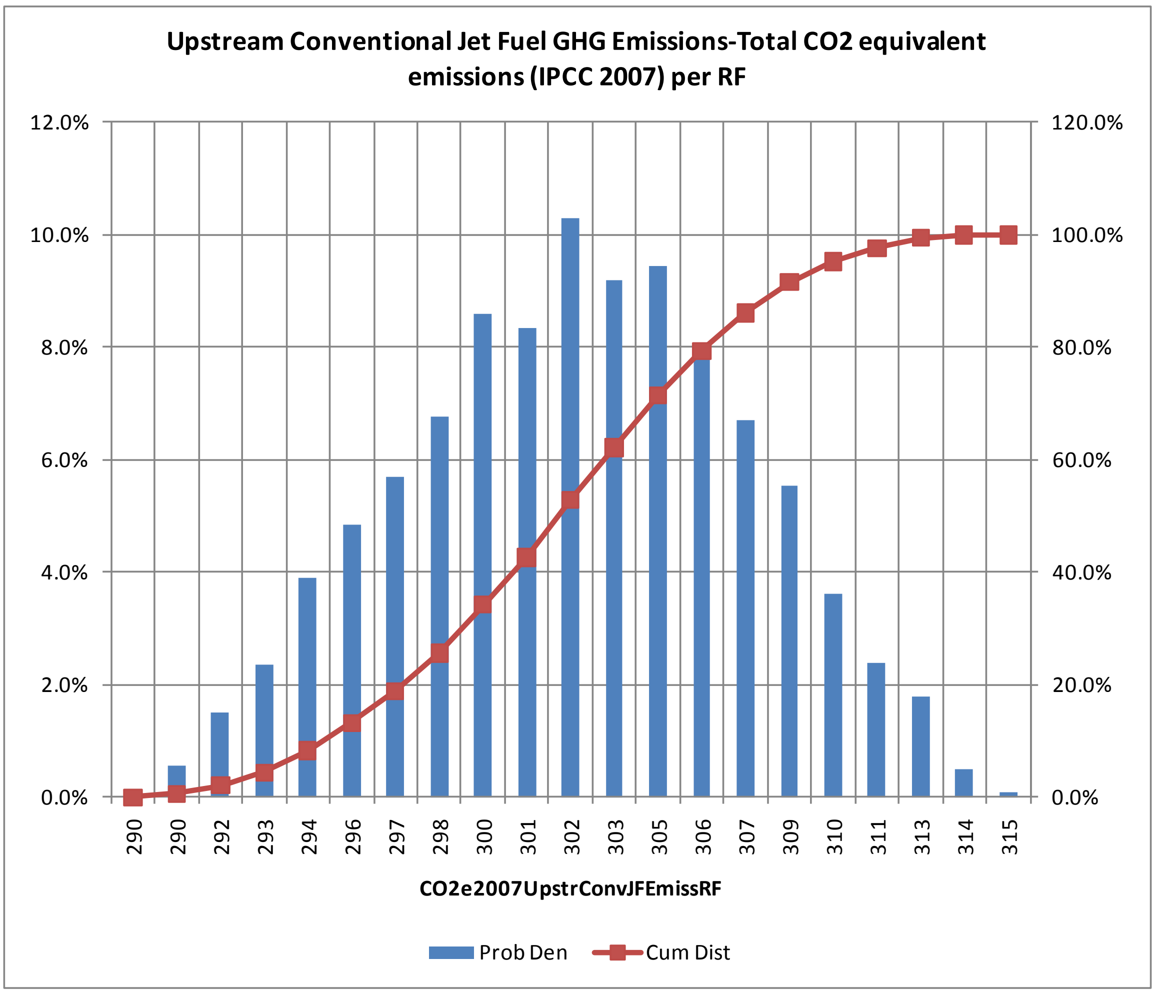


Figure 50. LC Stage #4b Probability Density Function and Cumulative Distribution of CO_2e Emissions (Using IPCC 2007 GWP) (per kg of Blended Jet Fuel Delivered to the Aircraft)

7.2.3.3 Sensitivity Analysis

In the sensitivity analysis, the total CO_2e emission using the IPCC 2007 global warming potentials was calculated for each key variable. Table 115 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions. The Absolute Difference for each key variable is also shown in the table, and key variables are listed from highest to lowest based on their Absolute Difference. The same results are presented graphically in Figure 51, which is a tornado chart.

For LC Stage #4b, one variable, the "Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced", has the most influence on the calculated CO_2e emissions. Two other variables, "Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced" and "Upstream N_2O Emitted per kg Conventional Jet Fuel Produced" also influence the calculated CO_2e emissions, but to a lesser extent.

Table 115. Sensitivity Analysis Results for Stage #4b Involving Upstream GHG Emissions from Production of Conventional Jet Fuel (Using IPCC 2007 GWP) (g CO_2e/kg Blended Jet Fuel Delivered to the Aircraft)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/tonne CO_2)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	290	315	24.7
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	3.61E-03	3.43E-03	3.79E-03	300	305	4.67
Upstream N_2O Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_N2O	kg N_2O/kWh	5.49E-05	5.21E-05	5.76E-05	302	303	0.846

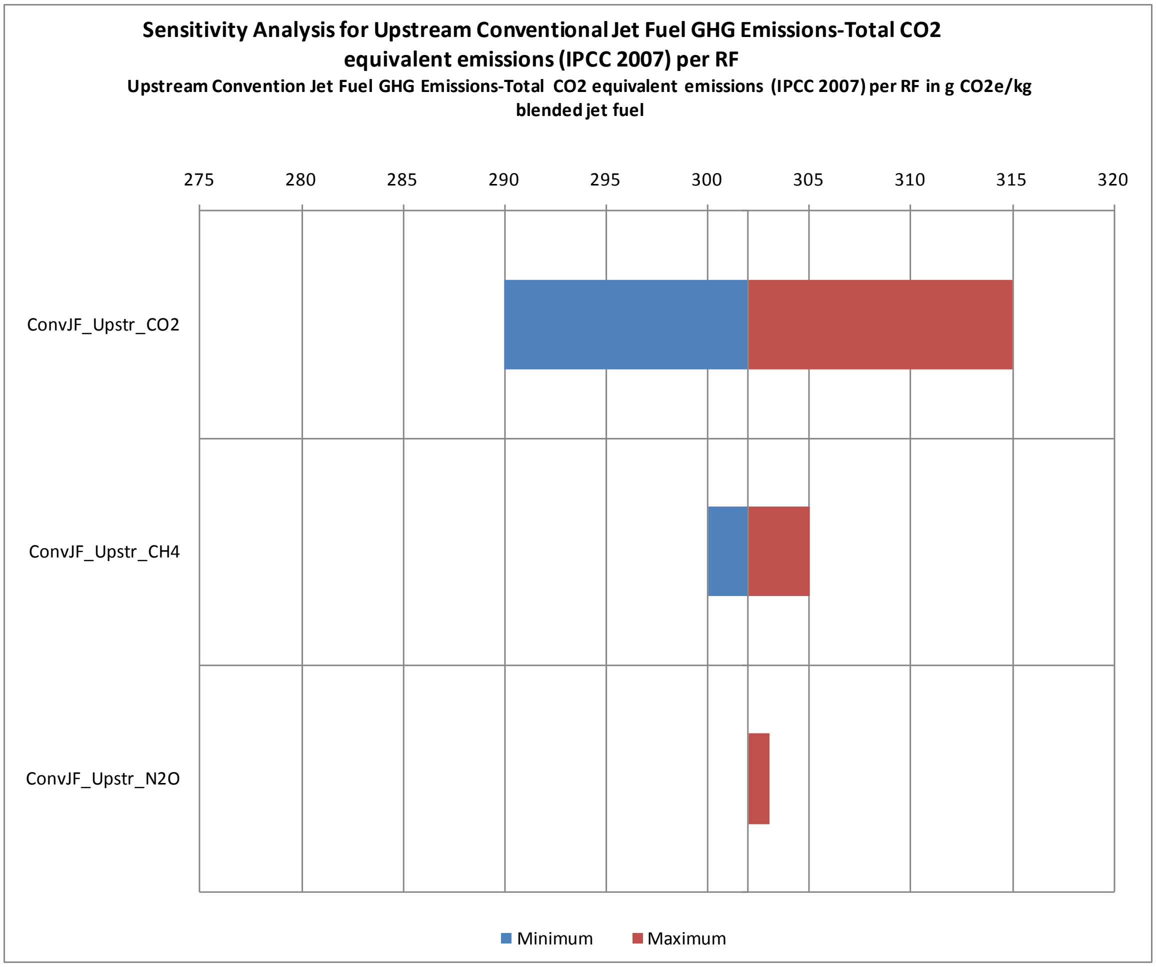


Figure 51. Sensitivity Analysis Results for Stage #4b Involving Upstream GHG Emissions from Production of Conventional Jet Fuel (Using IPCC 2007 GWP; g CO_2e per kg Blended Jet Fuel Delivered to the Aircraft)

7.3 Life cycle Stage #4c: Transport of Blended Jet Fuel

LC Stage #4c includes two options for the transport of blended jet fuel to an airport for consumption. The blended jet fuel is transported either to Chicago O'Hare Airport (Option 1), or to a combination of Chicago O'Hare Airport and smaller regional airports (Option 2).

7.3.1 Modeling Approach and Data Sources

Transport of blended jet fuel under LC Stage #4c is modeled according to two separate options. The first option involves exclusive delivery of the blended jet fuel to Chicago O'Hare Airport, and the second option involves delivery of the blended jet fuel to a combination of the Chicago O'Hare Airport and smaller regional airports. Stage #4a and #4b are the same for both options. The options only differ in terms of the manner in which the blended jet fuel is transported, and the final destination of the fuel following transport. The F-T Jet Fuel Spreadsheet Model assumes that one of two options would be implemented for the delivery of blended jet fuel to the boundary of LC Stage #5. Key modeling assumptions for this LC stage are shown in Table 116**.**

Table 116. Key Assumptions for Blended Jet Fuel Transport

Primary Subject	Assumption	Basis	Source
Option 1 Only			
Blended Jet Fuel Distribution	100% to Chicago O'Hare (pipeline)	Option 1 shows distribution to a single large facility	Study Value
Fuel Transport from Wood River Refinery to Chicago O'Hare Airport	245 miles	Estimated distance between Wood River Refinery and airport	Working Group Engineering Calculation
Option 2 Only			
Blended Jet Fuel Distribution	60% to Chicago O'Hare (pipeline), 40% to regional airports (tanker truck)	Option 2 involves distribution to a large facility, and several smaller facilities	Study Value
Fuel Transport Distance from Wood River Refinery to Terminal Facility	100 miles	Estimated point-to-point distance between Wood River Refinery and the terminal facility	Working Group Engineering Calculation
Fuel Transport Distance from Terminal Facility to Chicago O'Hare Airport	160 miles of pipeline	Estimated point-to-point distance between the terminal facility and Chicago O'Hare Airport	Working Group Engineering Calculation
Tanker Truck Transport Distance from Terminal Facility to Regional Airports	50 miles (100 miles round trip)	Estimated average distance between terminal facility and regional airports	Working Group Engineering Judgment
Constructed Facilities	Tanker trucks for blended jet fuel transport	Tanker trucks for transport to regional airports would be constructed	Study Value

7.3.1.1 Life Cycle Inventory Model

Figure 52 shows the individual processes that were modeled for LC Stage #4c. As shown, the model accounts for inputs of nylon, lead, steel, aluminum, polyurethane, and styrene-butadiene rubber as inputs for the truck cab and jet fuel tanker trailer construction. During operations, electricity is used for pumps that convey the blended jet fuel.

7.3.1.1.1 Option 1: 100 Percent Pipeline Transport to Major Airport (Base Case)

Under Option 1, pipeline transport would be used to transport blended jet fuel from the Wood River refinery directly to Chicago O'Hare Airport, 245 miles distant. This option includes operation of a pipeline that connects the refinery to Chicago O'Hare Airport, as well as fuel handling and transport operations at the airport. Electricity input and emissions associated with electricity production are considered for the pumps needed to pump the blended jet fuel along transport pipelines.

The model assumes, for Option 1, that all facilities needed for handling and transport operations, from the refinery through fuel handling and transport at the airport, would be pre-existing, and that no construction or manufacture of new facilities or infrastructure would be required. The Chicago O'Hare Airport is also considered existing for this study. The airport is defined as the fuel storage tank, fuel pumps, and dispensing stations. The energy needed within the airport to deliver the blended jet fuel to the aircraft fuel tank is considered negligible in this evaluation. The GHG emissions at the airport associated with handling the blended jet fuel are also assumed to be negligible. Electricity supplied by the regional electrical grid is assumed to power all pumps in the pipe line.

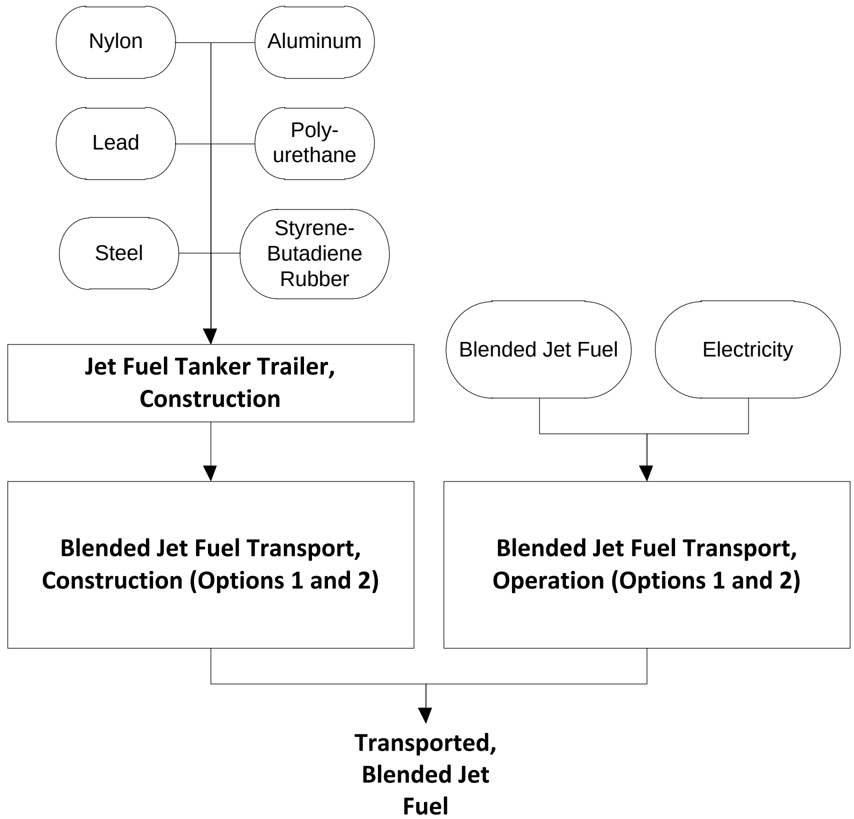


Figure 52. Process for Blended Jet Fuel Transport and Delivery

7.3.1.1.2 Option 2: 60 Percent Pipeline Transport to Major Airport and 40 Percent Truck Transport to Regional Airports

The purpose of Option 2 is to evaluate the potential for additional life cycle GHG emissions to occur as a result of distributing blended jet fuel to several airports, including smaller regional airports that could potentially be provided with such fuel. Under Option 2, transport of the blended jet fuel includes (1) operation of a pipeline from Wood River refinery that transports blended jet fuel to a bulk terminal facility 100 miles distant; (2) operation of a pipeline from the bulk terminal facility transporting 60 percent of the blended product to Chicago O’Hare Airport 160 miles distant; and (3) tanker truck transport operations that ship 40 percent of the blended product to regional airports, 50 miles distant (one way). Fuel handling, transport operations and associated GHG emissions at the airports are assumed to be negligible for this evaluation.

Electricity input and emissions associated with electricity production are considered for the pumps needed to pump the blended jet fuel from the refinery to the bulk terminal facility, and then from the terminal facility to Chicago O’Hare Airport. The emissions associated with the electricity used for operation of the bulk terminal facility are modeled eGRID 2007 data. Because no operational electricity use data were found for a bulk terminal facility, the energy use is assumed to be equivalent to that of a refueling station (fuel processing energy use only). This

assumption is considered valid because of the similar energy consuming components operating in a bulk terminal facility and in the fuel processing portions of a refueling station.

Unique to Option 2, diesel needed to fuel the tanker trucks used for transporting the F-T jet fuel is quantified, along with emissions associated with diesel combustion. Both the construction and operation of tanker trucks are included within the study boundary. An operation process is included for a Class 8B (> 60,000 lbs gross vehicle weight) truck-trailer combination to transport fuel to regional airports and then return (empty) to the bulk terminal facility. Conventional diesel fuel production and related fuel combustion emissions are the only two variables modeled as part of this transport process. The tanker truck transport process assumes that any potential loss of transported fuel during transport would be negligible, due to the relatively short distance traveled and the characteristics of the tanker trucks (they are designed to minimize volatile emissions).

The trucks are powered 100 percent by conventional diesel fuel. The average distance traveled is 50 miles, one-way, from the bulk terminal facility to a regional airport, for an average round-trip distance of 100 miles. Each trip services one regional airport and then returns to the bulk terminal facility. The fuel economy for Class 8B trucks ranges from 5 mpg with a full trailer to 9 mpg with the trailer empty based on recent US Department of Transportation statistics. These modeling assumptions are consistent with the fuel economy parameter used in the GREET model for heavy-duty truck transport (ANL, 2009).

The GREET model, Version 1.8 is used as the primary reference source for modeling fuel combustion emission for truck transport (ANL, 2009). The emission factors for Class 8B trucks is determined by the US EPA Office of Transportation and Air Quality Mobile 6 model and then incorporated into the GREET model. A representative average operating truck for the study period is used.

The emission factors are based on two variables: (1) the fuel economy of the truck (expressed in mpg) and (2) emission factors in grams per MMBtu of fuel consumed. The result is multiplied by the round trip distance traveled to obtain the mass of combustion emissions per the mass of fuel transported. Previous studies indicated that the fuel economy for Class 8B trucks remains relatively constant during delivery and return trip to the point of origin, therefore, no improvements to the fuel economy are considered for the return trip.

The Chicago O'Hare Airport for Option 2 would be the same as for Option 1. All facilities relevant to the study at the regional airports that receive deliveries under Option 2 are assumed to be pre-existing. The energy needed to deliver the blended jet fuel to the aircraft at the airport is considered negligible in this evaluation.

7.3.1.1.3 Implementation of LC Stage #4c in F-T Jet Fuel Spreadsheet Model

LC Stage #4c is implemented in the F-T Jet Fuel Spreadsheet Model through a number of sheets. For operations, all the input flows, output flows and GHG emissions are determined in sheet S4c.UP.O.JFTranOp. The input flows are:

- blended jet fuel leaving the Wood River refinery
- diesel fuel
- electricity

The output flows are:

- blended jet fuel delivered to an aircraft fuel tank

The GHG emissions are CO_2 from non-biogenic sources, CO_2 from biogenic sources (zero for this stage), CH_4 and N_2O.

The sheet includes additional flows to facilitate mass balance calculations. For blended jet fuel, additional flows include "jet fuel emitted to air (lost in transport) per kg of blended jet fuel delivered to aircraft". For GHGs, additional flows include "CO_2 to air from combustion", "CH_4 to air from combustion," and "N_2O to air from combustion". These latter variables reflect direct emissions of GHG from diesel fuel combustion.

Many of these flows are calculated with equations that have adjustable parameters or variables. A number of these variables are specified as random variables with an associated probability distribution. Thus, many of the flows are random variables. The equations used to calculate the various flows are presented in detail in sheets S4c.UP.O.JFTranOp and S4.UP.O.JFTranOp within the F-T Jet Fuel Spreadsheet Model. The variables specified as random variables are presented in the next section.

For construction, all the input flows, output flows and GHG emissions are determined in sheet S4c.UP.C.JFTranCon. This sheet, in turn, references information in sheets S4.UP.C.JFTranCon and S4.UP.C.Truck. The input flows for construction in this stage are:

- steel plate, BF (85% Recovery Rate)
- aluminum sheet
- lead (99.995%)
- nylon 6.6 granulate
- polyurethane flexible foam
- styrene-butadiene rubber (SBR)

The only output flow for construction is a constructed tanker trailer truck for transporting blended jet fuel.

The GHG emissions are CO_2 from non-biogenic sources, CO_2 from biogenic sources, CH_4 and N_2O. The direct GHG emissions for this unit process are all zero.

The sheet includes the following additional flows to facilitate mass balance calculations for GHGs: "CO_2 to air from combustion", "CH_4 to air from combustion,", and "N_2O to air from combustion". These flows are all zero for this unit process.

All of the input flows are random variables since they are specified through equations that have random variables with an associated distribution. The equations are presented in detail in sheets S4.UP.C.JFTranCon and S4.UP.C.Truck within the F-T Jet Fuel Spreadsheet Model. The variables specified as random variables are presented in the next section.

7.3.1.2 Key Modeling Variables

The key variables with respect to the emissions of GHGs during the transport of the blended jet fuel to an aircraft fuel tank are presented in Table 117. For each variable the best estimate is presented, along with the minimum value, maximum value, most likely value and the distribution assumed for the variable.

For most of the variables in Table 117, data were not readily available to estimate uncertainty, and/or to evaluate a most likely value. For these variables, the minimum and maximum values were assumed to be a multiple of the best estimate. If the uncertainty is low or moderate, the multiplier was 0.9 for the minimum value (i.e., 10 percent less than the best estimate) and 1.1 for the maximum value (i.e., 10 percent more than the best estimate). If the uncertainty is higher, the multiplier for the minimum value was lower and the multiplier for the maximum value was higher. Professional judgment was used to assess the level of uncertainty for each variable.

Table 117. Key Variables for LC Stage #4c and Ranges of Selected Values

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-Jet Fuel Blending and Transport Operation							
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	kWh/kg-mi	2.77E-05	2.49E-05	4.16E-05	2.77E-05	Triangular	Assumes that electricity required can vary between 10% lower and 50% higher than best estimate
Tortuosity Factor for Pipeline		0.1	0.05	0.2	0.1	Triangular	Assumes that tortuosity factor for pipeline can be 100% higher or 50% lower than best estimate
Point-to-point Distance from Petroleum Refinery in Wood River, Ill to O'Hare Airport	mi	245	221	270	245	Uniform	Assumes that distance for existing pipeline can vary between 10% lower and 10% higher than best estimate
Fraction Blended Jet Fuel Emitted to Air During Loading and Unloading of Bulk Storage Tank	kg/kg blended jet fuel	2.00E-06	1.00E-06	4.00E-06	2.00E-06	Triangular	Assumes that fraction emitted to atmosphere can vary between 50% lower and 100% higher than best estimate
Point-to-point Distance from Bulk Storage Terminal to O'Hare Airport	mi	160	144	176	160	Uniform	Assumes that distance for existing pipeline can vary between 10% lower and 10% higher than best estimate
One-way Distance Traveled by Tanker Trailer Truck	mi	50	38	63	50	Uniform	Assumes that distance can vary between 25% lower and 25% higher than best estimate
Diesel Fuel Economy for Tanker Trailer Loaded with Fuel	mi/gal	5.1	4.1	6.1	5.1	Uniform	Assumes that fuel mileage can vary between 20% lower and 20% higher than best estimate
Diesel Fuel Economy for Tanker Trailer Empty	mi/gal	9.4	7.5	11.3	9.4	Uniform	Assumes that fuel mileage can vary between 20% lower and 20% higher than best estimate
Input Parameters-Jet Fuel Blending and Transport Construction							
Steel Plate, BF (85% Recovery Rate) for All Pieces of Equipment	kg/kg blended jet fuel	1.35E-04	1.21E-04	1.48E-04	1.35E-04	Triangular	Assumes that material used can be 10% higher or 10% lower than best estimate
Aluminum Sheet for All Pieces of Equipment	kg/kg blended jet fuel	5.84E-05	5.26E-05	6.43E-05	5.84E-05	Triangular	Assumes that material used can be 10% higher or 10% lower than best estimate

Table 117. Key Variables for LC Stage #4c and Ranges of Selected Values *(Cont'd)*

Variable Name	Units	Best Estimate	Minimum	Maximum	Most Likely	Distribution	Discussion
Input Parameters-Jet Fuel Blending and Transport Construction (Cont'd)							
Lead (99.995%) for All Pieces of Equipment	kg/kg blended jet fuel	2.36E-06	2.12E-06	2.59E-06	2.36E-06	Triangular	Assumes that material used can be 10% higher or 10% lower than best estimate
Nylon 6.6 Granulate for All Pieces of Equipment	kg/kg blended jet fuel	4.20E-06	3.78E-06	4.63E-06	4.20E-06	Triangular	Assumes that material used can be 10% higher or 10% lower than best estimate
Polyurethane Flexible Foam (PU) for All Pieces of Equipment	kg/kg blended jet fuel	4.20E-06	3.78E-06	4.63E-06	4.20E-06	Triangular	Assumes that material used can be 10% higher or 10% lower than best estimate
Styrene-Butadiene_Rubber (SBR) for All Pieces of Equipment	kg/kg blended jet fuel	5.69E-05	5.12E-05	6.26E-05	5.69E-05	Triangular	Assumes that material used can be 10% higher or 10% lower than best estimate
Input Parameters- Upstream Emissions from Secondary Energy Unit Processes							
Upstream CO_2 Emitted per kg Petroleum Diesel Fuel Produced	kg CO_2/kg	0.72	0.68	0.75	0.72	Triangular	Assumed that upstream GHG emissions are -5% to +5% of best estimate
Upstream CH_4 Emitted per kg Petroleum Diesel Fuel Produced	kg CH_4/kg	4.00E-03	3.80E-03	4.20E-03	4.00E-03	Triangular	Assumed that upstream GHG emissions are -5% to +5% of best estimate
Upstream N_2O Emitted per kg Petroleum Diesel Fuel Produced	kg N_2O/kg	1.30E-05	1.23E-05	1.36E-05	1.30E-05	Triangular	Assumed that upstream GHG emissions are -5% to +5% of best estimate
Upstream CO_2 Emitted per kWh SERC Electricity Produced	kg CO_2/kWh	0.76	0.69	0.84	0.76	Triangular	Assumed that upstream GHG emissions are -10% to +10% of best estimate
Upstream CH_4 Emitted per kWh SERC Electricity Produced	kg CH_4/kWh	8.35E-04	7.52E-04	9.19E-04	8.35E-04	Triangular	Assumed that upstream GHG emissions are -10% to +10% of best estimate
Upstream N_2O Emitted per kWh SERC Electricity Produced	kg N_2O/kWh	1.01E-05	9.08E-06	1.11E-05	1.01E-05	Triangular	Assumed that upstream GHG emissions are -10% to +10% of best estimate

7.3.2 Data Quality Assessment

The results of unit process data quality evaluation for LC Stage #4c are provided in Table 118. Data quality indicators and life cycle significance determinations are listed for each unit process included in the model of this stage. Note that this significance check is based on results for the base case using jet fuel transport Option 1.

Analysis of the life cycle uncertainty significance of these processes shows that the composite construction process for transport of jet fuel (fourth row in the table below) is below the significance threshold for the jet fuel production life cycle. This result determines that, although DQI scores appear below the quality requirement of 1-2, the data used for the construction processes are acceptable. Option 1 contains poor completeness quality for data used to define the amount of electricity used in pipeline transport of jet fuel. Therefore the pipeline electricity use is flagged for sensitivity analysis. This parameter reappears in the Option 2 operations. In addition, poor temporal and geographic quality is noted for the evaporative diesel emissions from a bulk storage tank. Finally, the completeness, temporal representativeness, and geographic representativeness of tanker truck fuel economy data is flagged for sensitivity analysis.

Operations processes for both Option 1 and Option 2 of jet fuel transport operations contain data below the quality requirements of the study.

Table 118. LC Stage #4 Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Life Cycle Significance of Process (%)
1	Jet Fuel Transport, (Option 1) Operation	1,3,2,2,2	6.4%
1	Jet Fuel Transport, (Option 2) Operation	2,3,4,3,3	***
1	Jet Fuel Transport, Construction	2,2,3,3,2	0.0%
2	Jet Fuel Pipeline, Construction	2,2,3,2,2	
2	Jet Fuel Tanker Trailer, Construction	2,2,3,3,1	

*** Life cycle significance determinations were made with respect to Option 1 of jet fuel transport. A comparative case using Option 2 was also run; determining jet fuel transport under Option 1 to be significant, however, the significance value is not directly comparable to the other values in this table.

7.3.3 Results

This section presents the life cycle GHG emissions for LC Stage #4, including the following components: (1) deterministic results, where deterministic means that the results are based on setting each variable that is uncertain to its best estimate; (2) the range in GHG emissions when variables that are uncertain are allowed to be varied in a probabilistic simulation; and (3) an analysis of the influence of each uncertain variable on GHG emissions when the uncertain variables are systematically varied in a sensitivity analysis.

7.3.3.1 Deterministic Greenhouse Gas Emissions

The deterministic results for Stage #4c are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S4c.Summ, which presents the input flows, output flows (products and co-products) and GHG emissions for this stage. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the

functional unit. GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are presented in this sheet.

Table 119 and Table 120 present the life cycle GHG emissions for LC Stage #4 in terms of the reference flow for this stage, which is 1 kg of blended jet fuel delivered to the aircraft fuel tank. Table 119 presents GHG emissions for Option 1, transport of all blended jet fuel to O'Hare airport. Table 120 presents GHG emissions for Option 2, transport of 60 percent of blended jet fuel to O'Hare airport and 40 percent of blended jet fuel to regional airports. These tables present the total emissions of 1) non-biogenic carbon dioxide from operation and construction, 2) biogenic carbon dioxide from operation and construction, 3) methane from operation and construction, 4) nitrous oxide from operation and construction and 5) other GHGs from operation and construction. This last category, other GHGs, captures emissions from GHGs other than carbon dioxide, methane or nitrous oxide, or emissions that are expressed in carbon dioxide equivalents and cannot be differentiated into the primary GHGs. The second column in the tables presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the IPCC 2007, IPCC 2001 and IPCC 1996 estimates, respectively.

The total CO_2e emissions for Option 2 are approximately 50 percent higher than the CO_2e emissions for Option 1. The greenhouse gas emissions for Option 2 are higher because more energy is used to transport the fuel by truck than used for pipeline transport. Approximately 97 percent of the total CO_2e emissions are due to CO_2, with the remainder due to CH_4. For Option 1, 100 percent of the CO_2e emissions are due to operations, while for Option 2, approximately 97 percent of the CO_2e emissions are due to operations.

Table 119. LC Stage #4c GHG Emissions for Option 1: All Blended Jet Fuel to O'Hare Airport (per kg of Blended Jet Fuel Delivered to the Aircraft)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/kg Blended Jet Fuel)	Mass of GHG Emitted to Atmosphere (g CO_2e/ kg Blended Jet Fuel) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/ kg Blended Jet Fuel) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/ kg Blended Jet Fuel) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	5.7	5.7	5.7	5.7
Non-biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Non-biogenic CO_2 – Subtotal	5.7	5.7	5.7	5.7
Biogenic CO_2 – Operation	0.0	0.0	0.0	0.0
Biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Biogenic CO_2 – Subtotal	0.0	0.0	0.0	0.0
CH_4 – Operation	0.01	0.2	0.1	0.1
CH_4 – Construction	0.00	0.0	0.0	0.0
CH_4 – Subtotal	0.01	0.2	0.1	0.1
N_2O – Operation	0.000	0.0	0.0	0.0
N_2O – Construction	0.000	0.0	0.0	0.0
N_2O – Subtotal	0.000	0.0	0.0	0.0
Other GHG – Operation		0.0	0.0	0.0
Other GHG – Construction		0.0	0.0	0.0
Other GHG – Subtotal		0.0	0.0	0.0
Operation – Total		5.9	5.8	5.8
Construction– Total		0.0	0.0	0.0
Grand Total		5.9	5.8	5.8

Note: Subtotals and totals may not sum exactly due to rounding.

Table 120. LC Stage #4c GHG Emissions for Option 2: 60% of Blended Jet Fuel to O'Hare Airport and 40% of Blended Jet Fuel to Regional Airports (per kg of Blended Jet Fuel Delivered to the Aircraft)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/kg Blended Jet Fuel)	Mass of GHG Emitted to Atmosphere (g CO_2e/ kg Blended Jet Fuel) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/ kg Blended Jet Fuel) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/ kg Blended Jet Fuel) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	8.3	8.3	8.3	8.3
Non-biogenic CO_2 – Construction	0.3	0.3	0.3	0.3
Non-biogenic CO_2 – Subtotal	8.6	8.6	8.6	8.6
Biogenic CO_2 – Operation	0.0	0.0	0.0	0.0
Biogenic CO_2 – Construction	0.0	0.0	0.0	0.0
Biogenic CO_2 – Subtotal	0.0	0.0	0.0	0.0
CH_4 – Operation	0.01	0.2	0.2	0.2
CH_4 – Construction	0.00	0.0	0.0	0.0
CH_4 – Subtotal	0.01	0.2	0.2	0.2
N_2O – Operation	0.000	0.0	0.0	0.0
N_2O – Construction	0.000	0.0	0.0	0.0
N_2O – Subtotal	0.000	0.0	0.0	0.0
Other GHG – Operation		0.0	0.0	0.0
Other GHG – Construction		0.0	0.0	0.0
Other GHG – Subtotal		0.0	0.0	0.0
Operation – Total		8.5	8.5	8.5
Construction– Total		0.3	0.3	0.3
Grand Total		8.8	8.8	8.8

Note: Subtotals and totals may not sum exactly due to rounding.

7.3.3.2 Probabilistic Uncertainty Analysis

In an attempt to quantify the influence of uncertainty in the key variables presented in Table 117 on the calculated GHG emissions, probabilistic simulations were performed. In this evaluation, probabilistic simulations were performed for total life cycle GHG emissions using the IPCC 2007 global warming potentials. CO_2 equivalent emissions were calculated relative to the stage reference flow of 1 kg of blended jet fuel delivered to the aircraft fuel tank. Table 121 presents the statistics for the CO_2e emissions developed from the simulations for the two Options. Figure 53 and Figure 54 present the cumulative distribution and probability density function for CO_2 equivalent emissions relative to the LC Stage #4c reference flow for Options 1 and 2, respectively. In Figure 53 and Figure 54, the vertical scale on the left is for the probability density function and the vertical scale on the right is for the cumulative distribution.

For Option 1 (100 percent of the blended jet fuel transported to O'Hare airport), the CO_2 equivalent emissions relative to the reference flow range from 4.6 to 11 g CO_2e/kg blended jet fuel with a median value of 6.7 g CO_2e/ kg blended jet fuel, a mean of 6.9 g CO_2e/ kg blended jet fuel and a standard deviation of 0.99 g CO_2e/ kg blended jet fuel. Eighty percent of the distribution lies between 5.7 and 8.2 g CO_2e/ kg blended jet fuel and the middle fifty percent of the distribution lies between 6.1 and 7.5 g CO_2e/ kg blended jet fuel.

For Option 2 (60 percent of the blended jet fuel transported to O'Hare airport and 40 percent of the blended jet fuel transported to regional airports), the CO_2 equivalent emissions relative to the reference flow range from 7.3 to 13 g CO_2e/kg blended jet fuel with a median value of 9.6 g CO_2e/ kg blended jet fuel, a mean of 9.7 g CO_2e/ kg blended jet fuel and a standard deviation of 0.95 g CO_2e/ kg blended jet fuel. Eighty percent of the distribution lies between 8.5 and 11 g CO_2e/ kg blended jet fuel and the middle fifty percent of the distribution lies between 9 and 10 g CO_2e/ kg blended jet fuel. The distributions for both Options 1 and 2 are very narrow because most of the CO_2e emissions come from upstream emissions from conventional jet fuel which are not treated probabilistically.

Table 121. LC Stage #4c: Probabilistic Uncertainty Analysis for Options 1 and 2; Statistics for CO_2e Emissions

Statistical Parameter	Mass of GHG Emitted to Atmosphere by Option 1 (g CO_2e/kg blended jet fuel) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere by Option 2 (g CO_2e/kg blended jet fuel) (IPCC 2007 GWP)
Minimum	4.6	7.3
10%	5.7	8.5
25%	6.1	9.0
Median (50%)	6.7	9.6
75%	7.5	10.0
90%	8.2	11.0
Maximum	11.0	13.0
Mean	6.9	9.7
Mode	6.5	9.7
Stand. Deviation	0.99	0.95

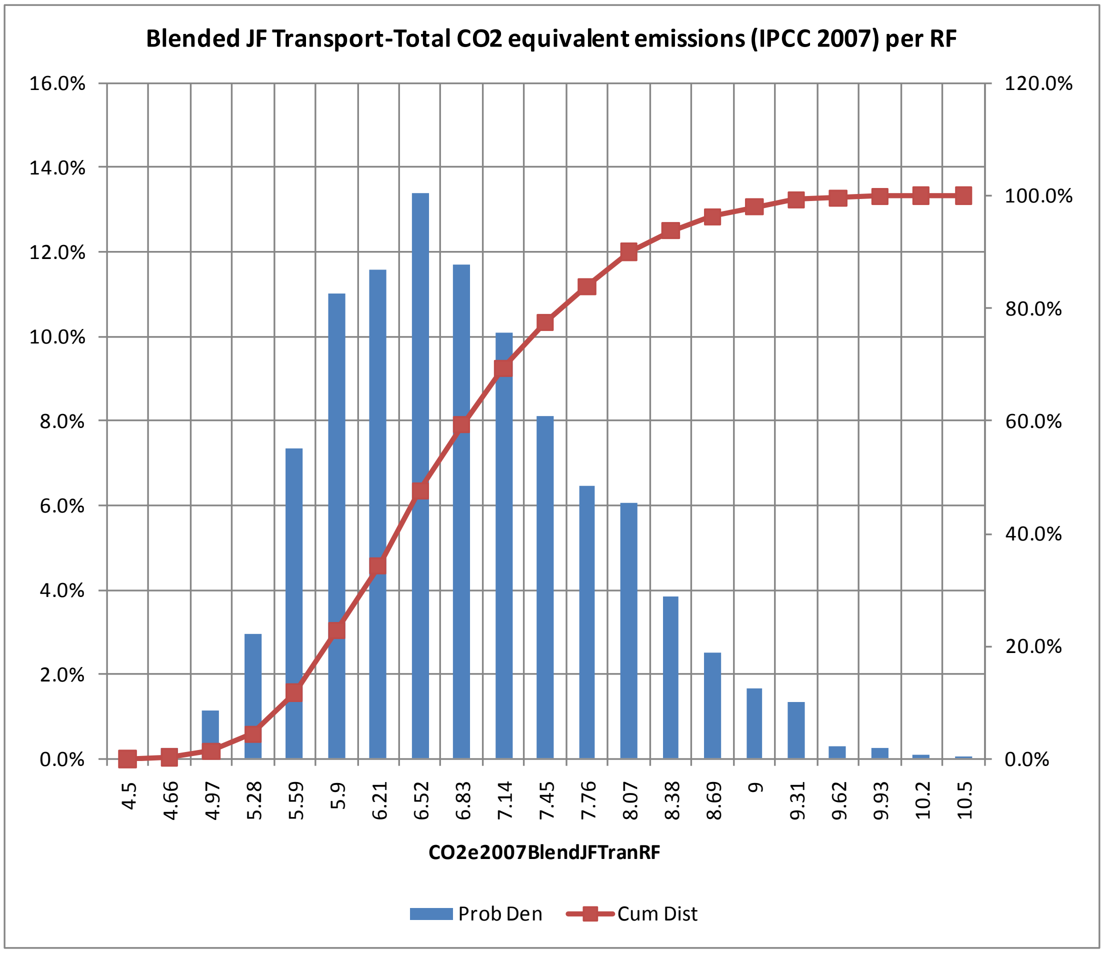


Figure 53. LC Stage #4c Probability Density Function and Cumulative Distribution of CO_2e Emissions for Option 1 (Using IPCC 2007 GWP) (per kg of Blended Jet Fuel Delivered to the Aircraft)

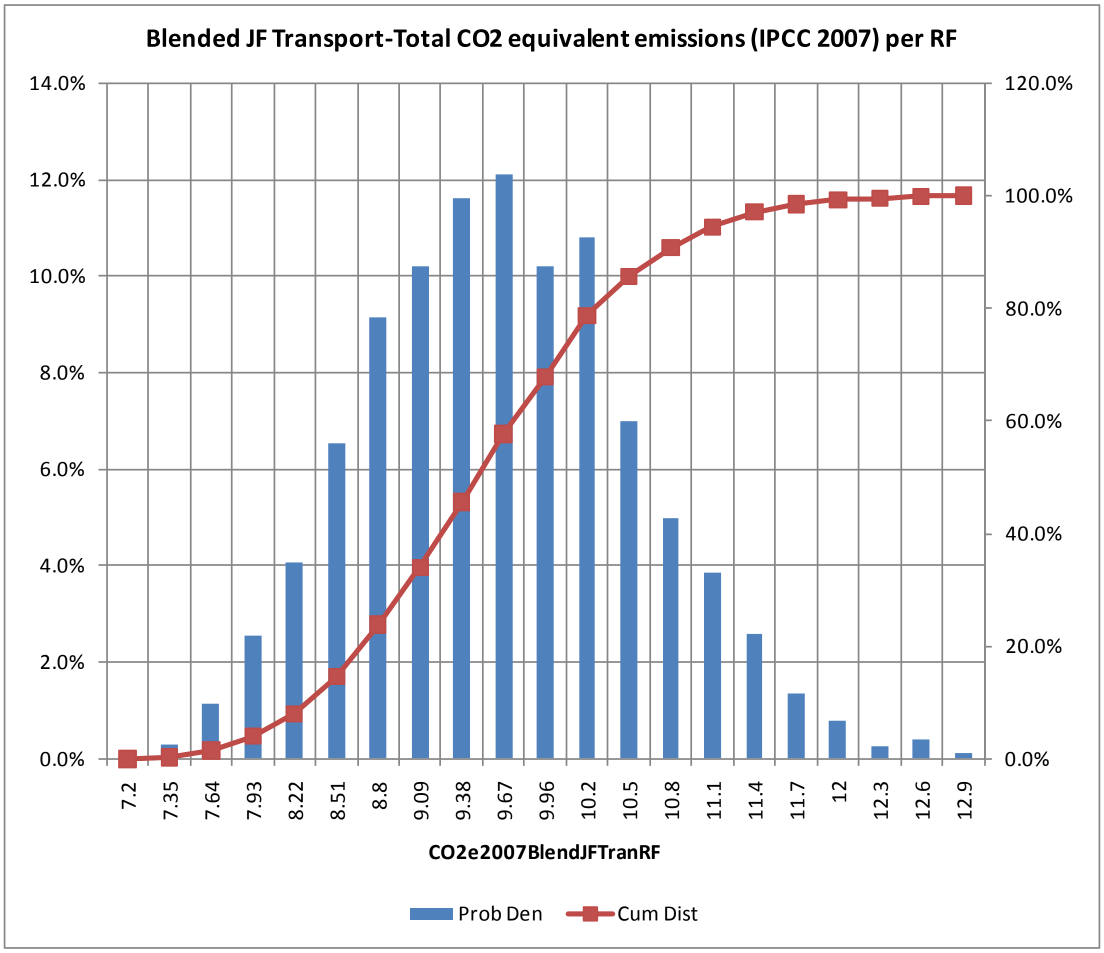


Figure 54. LC Stage #4c Probability Density Function and Cumulative Distribution of CO_2e Emissions for Option 2 (Using IPCC 2007 GWP) (per kg of Blended Jet Fuel Delivered to the Aircraft)

7.3.3.3 Sensitivity Analysis

In the sensitivity analysis, the total CO_2e emission using the IPCC 2007 global warming potentials was calculated for each key variable. Table 122 presents the key variables, their best estimate, their minimum value, their maximum value, and associated minimum and maximum total CO_2e emissions for Option 1. Table 123 presents the same information for Option 2. The Absolute Difference for each key variable is also shown in the two tables, and key variables are listed from highest to lowest based on their Absolute Difference. The same results are presented graphically in Figure 55 and Figure 56, which are tornado charts.

For Option 1 (100 percent transport of blended jet fuel to O'Hare airport), one variable, the "Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled", has the most influence on the calculated CO_2e emissions. Three other variables, "Pipeline Tortuosity", "Point-to-point Distance from Petroleum Refinery in Wood River, Ill to O'Hare Airport", and "Upstream CO_2 Emitted per kWh SERC Electricity Produced", also influence the calculated CO_2e emissions, but to a lesser extent. The remaining variables have little influence on the calculated CO_2e emissions.

For Option 2 (transport of 60 percent of blended jet fuel to O'Hare airport and transport of 40 percent of blended jet fuel to regional airports), one variable, the "Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled", has the most influence on the calculated CO_2e emissions. This variable also had the most influence on CO_2e emissions for Option 1. Six other variables, "One-way Distance Traveled by Tanker Trailer Truck", "Pipeline Tortuosity", "Diesel Fuel Economy for Tanker Trailer Loaded with Fuel", "Point-to-point Distance from CBTL facility to Petroleum Refinery in Wood River, Ill", "Point-to-point Distance from Bulk Storage Terminal to O'Hare Airport", and "Diesel Fuel Economy for Tanker Trailer Empty", also influence the calculated CO_2e emissions, but to a lesser extent. The remaining variables have little influence on the calculated CO_2e emissions.

Table 122. Sensitivity Analysis Results for LC Stage #4c Option 1 of Jet Fuel Transport (Using IPCC 2007 GWP) (g CO_2e/kg Blended Jet Fuel Delivered to the Aircraft)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/kg Blended Jet Fuel Delivered to the Aircraft)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and Mile Traveled	Elec_Pipe_kg_mi	kWh/kg-mi	2.77E-05	2.49E-05	4.16E-05	5.33	8.89	3.56
Point-to-point Distance from Petroleum Refinery in Wood River, Ill to O'Hare Airport	Ref_Airp_Dis1_mi	mi	245	221	270	5.33	6.52	1.19
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	5.35	6.5	1.15
Pipeline Tortuosity	Pipe_Tort1		0.1	0.05	0.2	5.61	6.67	1.05
Upstream CH_4 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CH4	kg CH_4/kWh	8.35E-04	7.52E-04	9.19E-04	5.91	5.94	3.15E-02
Upstream N_2O Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_N2O	kg N_2O/kWh	1.01E-05	9.08E-06	1.11E-05	5.92	5.93	4.54E-03
Diesel Fuel Economy for Tanker Trailer Loaded with Fuel	Trail_mpg_load	mi/gal	5.1	4.08	6.12	5.93	5.93	0
Diesel Fuel Economy for Tanker Trailer Empty	Trail_mpg_empty	mi/gal	9.4	7.52	11.3	5.93	5.93	0
Steel Plate, BF (85% Recovery Rate) for All Pieces of Equipment	Stl_Plt_BF85_BlendJF_kg	kg/kg blended jet fuel	1.35E-04	1.21E-04	1.48E-04	5.93	5.93	0
Aluminum Sheet for All Pieces of Equipment	AlumSht1_BlendJF_kg	kg/kg blended jet fuel	5.84E-05	5.26E-05	6.43E-05	5.93	5.93	0
Lead (99.995%) for All Pieces of Equipment	Lead1_BlendJF_kg	kg/kg blended jet fuel	2.36E-06	2.12E-06	2.59E-06	5.93	5.93	0
Nylon 6.6 Granulate for All Pieces of Equipment	Nylon_66_Gran_BlendJF_kg	kg/kg blended jet fuel	4.20E-06	3.78E-06	4.63E-06	5.93	5.93	0
Polyurethane Flexible Foam (PU) for All Pieces of Equipment	PUFF1_BlendJF_kg	kg/kg blended jet fuel	4.20E-06	3.78E-06	4.63E-06	5.93	5.93	0
Styrene-Butadiene_Rubber (SBR) for All Pieces of Equipment	SBR1_BlendJF_kg	kg/kg blended jet fuel	5.69E-05	5.12E-05	6.26E-05	5.93	5.93	0

Table 122. Sensitivity Analysis Results for LC Stage #4c Option 1 of Jet Fuel Transport (Using IPCC 2007 GWP) (g CO_2e/kg Blended Jet Fuel Delivered to the Aircraft) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/kg Blended Jet Fuel Delivered to the Aircraft)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CO_2 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CO2	kg CO_2/kg	0.718	0.683	0.754	5.93	5.93	0
Upstream CH_4 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CH4	kg CH_4/kg	0.004	0.0038	0.0042	5.93	5.93	0
Upstream N_2O Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_N2O	kg N_2O/kg	1.30E-05	1.23E-05	1.36E-05	5.93	5.93	0
One-way Distance Traveled by Tanker Trailer Truck	Trail_Dis_1way_mi	mi	50	37.5	62.5	5.93	5.93	0
Point-to-point Distance from Bulk Storage Terminal to O'Hare Airport	Bulk_Airp_Dis3_mi	mi	160	144	176	5.93	5.93	0
Fraction Blended Jet Fuel Emitted to Air During Loading and Unloading of Bulk Storage Tank	BlendJF_Frac_Emit_Bulk	kg/kg blended jet fuel	2.00E-06	1.00E-06	4.00E-06	5.93	5.93	0

Table 123. Sensitivity Analysis Results for LC Stage #4c Option 2 of Jet Fuel Transport (Using IPCC 2007 GWP) (g CO_2e/ kg Blended Jet Fuel Delivered to Aircraft)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/kg Blended Jet Fuel Delivered to the Aircraft)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and Mile Traveled	Elec_Pipe_kg_mi	kWh/kg-mi	2.77E-05	2.49E-05	4.16E-05	8.36	11.2	2.84
One-way Distance Traveled by Tanker Trailer Truck	Trail_Dis_1way_mi	mi	50	37.5	62.5	7.97	9.71	1.74
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	8.35	9.33	0.979
Diesel Fuel Economy for Tanker Trailer Loaded with Fuel	Trail_mpg_load	mi/gal	5.1	4.08	6.12	9.4	8.46	0.939
Pipeline Tortuosity	Pipe_Tort1		0.1	0.05	0.2	8.59	9.43	0.842
Diesel Fuel Economy for Tanker Trailer Empty	Trail_mpg_empty	mi/gal	9.4	7.52	11.3	9.14	8.63	0.509
Point-to-point Distance from Bulk Storage Terminal to O'Hare Airport	Bulk_Airp_Dis3_mi	Mi	160	144	176	8.6	9.07	0.464
Upstream CO_2 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CO2	kg CO_2/kg	0.718	0.683	0.754	8.81	8.87	0.0632
Steel Plate, BF (85% Recovery Rate) for All Pieces of Equipment	Stl_Plt_BF85_BlendJF_kg	kg/kg blended jet fuel	1.35E-04	1.21E-04	1.48E-04	8.82	8.85	0.0323
Upstream CH_4 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CH4	kg CH_4/kWh	8.35E-04	7.52E-04	9.19E-04	8.82	8.85	0.0268
Upstream CH_4 Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_CH4	kg CH_4/kg	0.004	0.0038	0.0042	8.83	8.84	8.80E-03
Aluminum Sheet for All Pieces of Equipment	AlumSht1_BlendJF_kg	kg/kg blended jet fuel	5.84E-05	5.26E-05	6.43E-05	8.83	8.84	8.56E-03
Styrene-Butadiene_Rubber (SBR) for All Pieces of Equipment	SBR1_BlendJF_kg	kg/kg blended jet fuel	5.69E-05	5.12E-05	6.26E-05	8.83	8.84	8.22E-03
Nylon 6.6 Granulate for All Pieces of Equipment	Nylon_66_Gran_BlendJF_kg	kg/kg blended jet fuel	4.20E-06	3.78E-06	4.63E-06	8.83	8.84	8.17E-03

Table 123. Sensitivity Analysis Results for LC Stage #4c Option 2 of Jet Fuel Transport (Using IPCC 2007 GWP) (g CO_2e/ kg Blended Jet Fuel Delivered to Aircraft) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/kg Blended Jet Fuel Delivered to the Aircraft)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Polyurethane Flexible Foam (PU) for All Pieces of Equipment	PUFF1_BlendJF_kg	kg/kg blended jet fuel	4.20E-06	3.78E-06	4.63E-06	8.84	8.84	3.97E-03
Upstream N_2O Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_N2O	kg N_2O/kWh	1.01E-05	9.08E-06	1.11E-05	8.84	8.84	3.86E-03
Lead (99.995%) for All Pieces of Equipment	Lead1_BlendJF_kg	kg/kg blended jet fuel	2.36E-06	2.12E-06	2.59E-06	8.84	8.84	6.53E-04
Upstream N_2O Emitted per kg Petroleum Diesel Fuel Produced	Dies_Upstr_N2O	kg N_2O/kg	1.30E-05	1.23E-05	1.36E-05	8.84	8.84	3.41E-04
Fraction Blended Jet Fuel Emitted to Air During Loading and Unloading of Bulk Storage Tank	BlendJF_Frac_Emit_Bulk	kg/kg blended jet fuel	2.00E-06	1.00E-06	4.00E-06	8.84	8.84	5.26E-06
Point-to-point Distance from Petroleum Refinery in Wood River, Ill to O'Hare Airport	Ref_Airp_Dis1_mi	mi	245	221	270	8.84	8.84	0

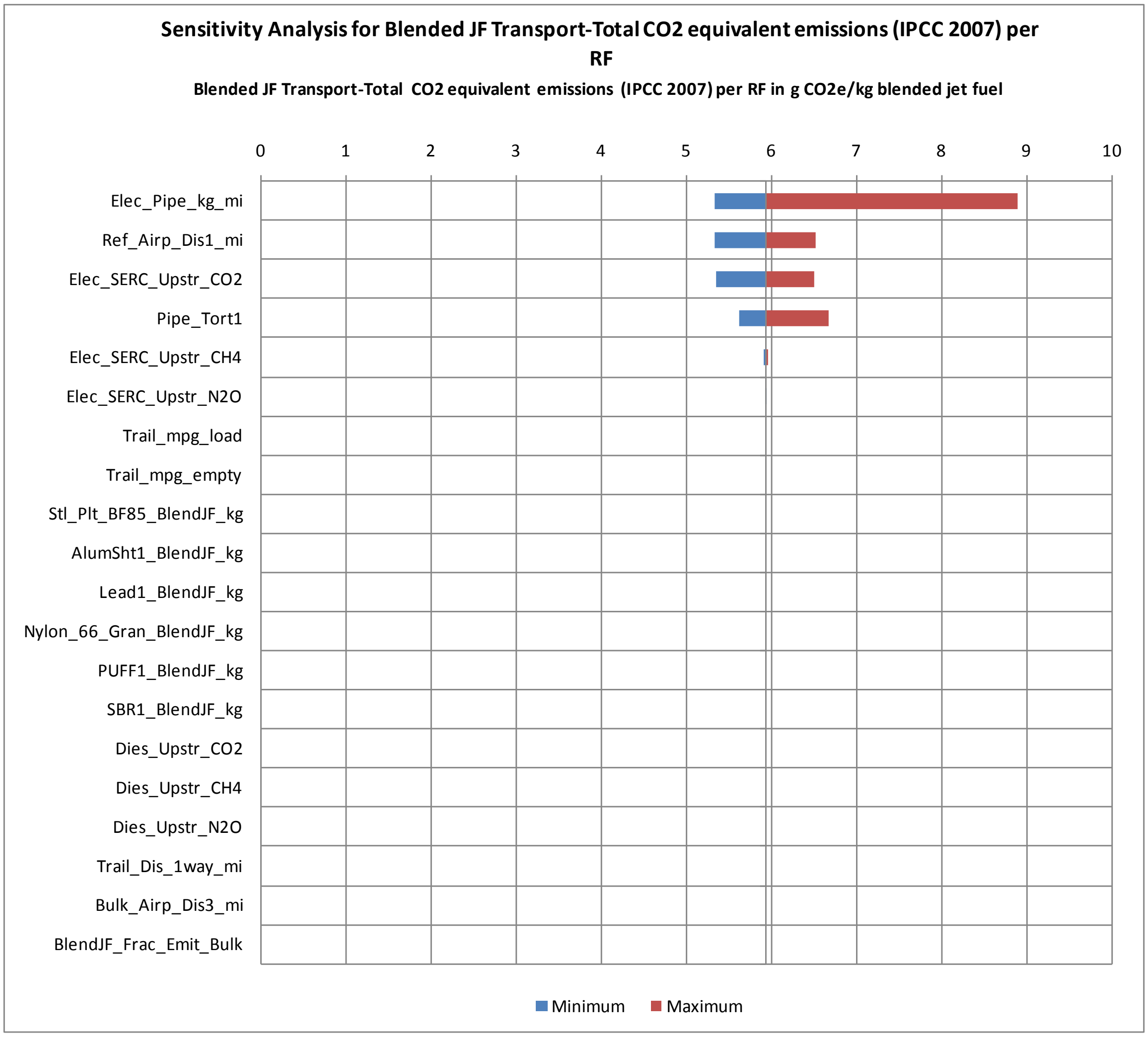


Figure 55. Sensitivity Analysis Results for LC Stage #4c Option 1 of Jet Fuel Transport (100% Transport to O'Hare) (Using IPCC 2007 GWP; g CO_2e per kg Blended Jet Fuel Delivered to the Aircraft)

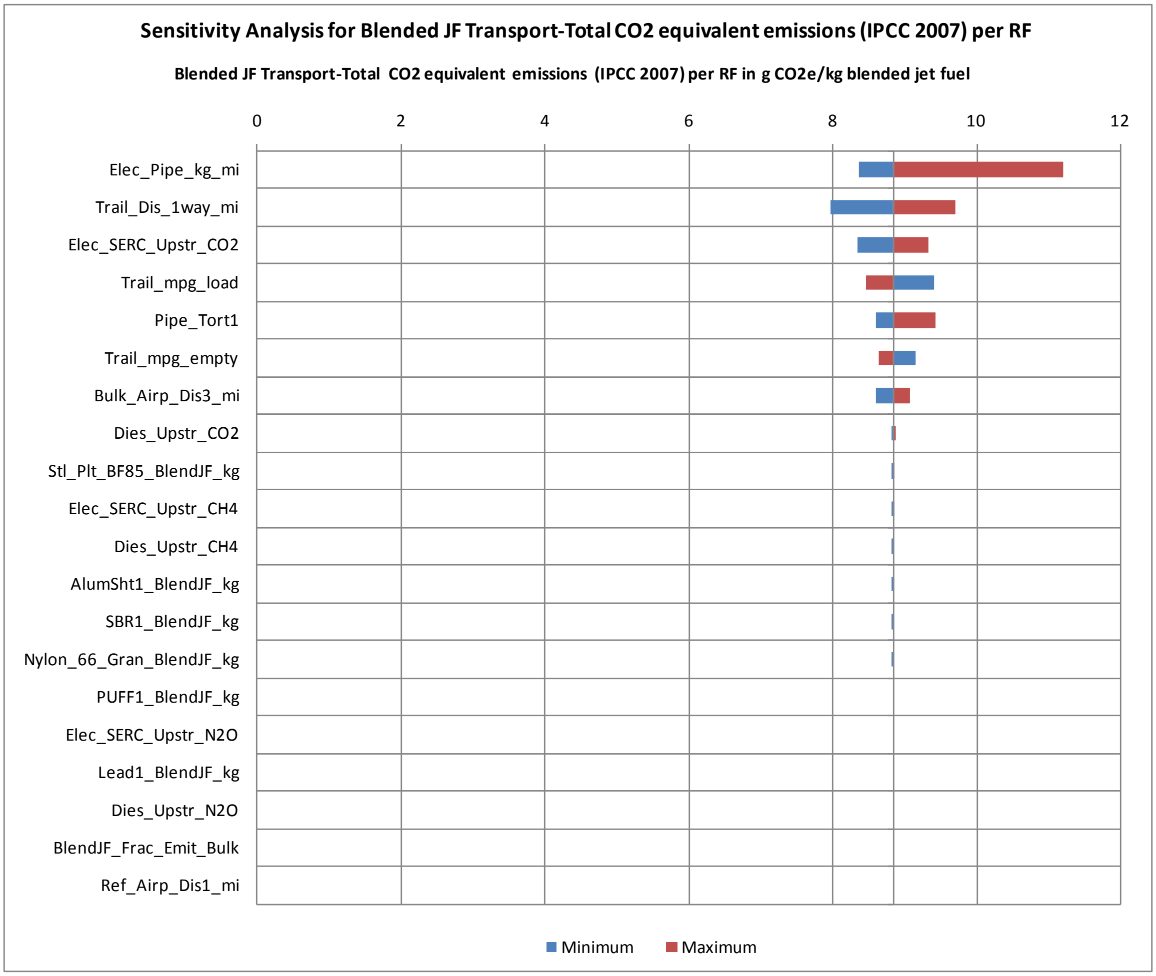


Figure 56. Sensitivity Analysis Results for LC Stage #4c Option 2 of Jet Fuel Transport (60% Transport to O'Hare and 40% Transport to Regional Airports) (Using IPCC 2007 GWP; g CO_2e per kg Blended Jet Fuel Delivered to the Aircraft)

8.0 LC STAGE #5: USE/AIRCRAFT OPERATION

LC Stage #5 includes the final use of the blended jet fuel produced in this LCA. Blended jet fuel is delivered to the boundary of LC Stage #5 following pipeline and tanker truck transport and delivery under LC Stage #4. In LC Stage #5, the fuel is presumed to be combusted in a jet engine. As described below, due to data limitations, only carbon dioxide emissions associated with jet fuel combustion are considered. The LC Stage ends immediately following combustion of the jet fuel, and emission of associated combustion gases.

8.1 Modeling Approach and Data Sources

The life cycle emissions that result from the creation and use of a fuel have both a direct radiative impact on the atmosphere, as well as an indirect effect by reacting chemically within the atmosphere to affect other compounds that have radiative impact. In this fashion, a life-cycle inventory of GHGs is an accounting for all of the emissions that contribute to global climate change. An accounting of these emissions is a proxy for the actual physical impact of increased global temperatures as well as socio-economic impacts of changed weather patterns, sea level rise, ocean acidity, and other outcomes. These distinctions are especially important when considering emissions from the combustion of fuels within a jet engine.

As represented in **Equation 23**, the principal products resulting from the combustion of jet fuel are CO_2 and H_2O, but the combustion also results in the creation of SO_X, NO_X, CO, unburned hydrocarbons (UHC), and fine particulate matter (PM).

Equation 23 $$\text{Fuel} + \text{Air}\ (O_2 + N_2) \rightarrow CO_2 + H_2O + SO_x + NO_x + PM + CO + UHC$$

The mass of emissions per mass of fuel consumed, a quantity known as an emissions index or emissions factor, have been compiled for all of the quantities listed in **Equation 23** for both commercial and military jet engines. It is important to note that the emissions indices of PM, CO, UHC, and NO_X vary with engine operation (e.g., idle, takeoff, and cruise operations), and that there are recommended practices for estimating the time and fuel use in each operating mode. The interested reader is directed to Kim, et al. (2007) to learn more about the System for assessing Aviation's Global Emissions (SAGE) tool, which is used to create annual emissions inventories for the US FAA.

Alternative fuels may change the emissions produced by aircraft. For example, because the chemical composition of the F-T jet fuel considered in this study differs from that of conventional jet fuel, there will be changes in the combustion products, as compared to petroleum-derived fuels. Knowledge of these changes varies with our fundamental understanding of how these pollutants are created. The emissions of CO_2, H_2O, and SO_X can be estimated for any fuel composition, including F-T jet fuel, based on complete combustion. These emissions indices (EI) are summarized along with the carbon mass fraction of the fuel in Table 124 (Hileman et al., 2010). Because complete combustion of the fuel has been assumed, (i.e., all fuel carbon is assumed to be converted to CO_2 via combustion), the life cycle inventory results would be the same whether the fuel were used in a jet aircraft or a diesel engine.

Table 124. Compositional Properties and Emission Indices for CO_2 (Hileman et al., 2010)

Fuel	Carbon Mass Fraction	Energy Content (MJ/kg)	CO_2e (g/kg)	CO_2e (g/MJ)
JP-8	0.862	43.2	3,159	73.1
F-T Jet Fuel	0.847	44.1	3,105	70.4

The F-T jet fuel compositional properties in Table 124 are based on measured properties for typical F-T jet fuels. In evaluation presented in this case study, the properties of the F-T jet fuel were determined based on the results of the ASPEN modeling of the CBTL facility (as discussed in **Section 6**) and other calculations. Table 125 presents the compositional properties of the F-T jet fuel generated by the CBTL process evaluated in this study. Even though these values differ from those observed by measurement of actual fuels, they were used for this case study to ensure consistency of results. The carbon mass fraction and density of the F-T jet fuel varied depending on whether the catalyst used in the F-T process was iron or cobalt. The energy content did not vary with the type of catalyst.

Table 125. Compositional Properties of F-T Jet Fuel from CBTL

Fuel	Carbon Mass Fraction	Energy Content (MJ/kg)	Density (kg/L)
F-T Jet Fuel (Iron Catalyst)	0.850	44.7	0.751
F-T Jet Fuel (Cobalt Catalyst)	0.848	44.7	0.754

Measurements indicate that the use of F-T jet fuel could result in no change in NO_X emissions to a reduction of up to 10 percent, relative to JP-8 (Dewitt et al. (2008); Timko et al. (2008); Bester and Yates (2009); and Miake-Lye (2010)). NO_X is produced by the oxidation of atmospheric nitrogen during combustion; for gas turbine engines, NO_X formation is largely a function of combustion temperature. Estimation of other byproducts, such as PM, CO, and UHC (which are the result of incomplete fuel combustion) are less understood, even for conventional jet fuel. However, measurements consistently indicate that there is a substantial decrease in PM emissions with the use of F-T jet fuels in gas turbine engines (Corporan et al. (2007a and 2007b); Dewitt et al. (2008); Timko et al. (2008); Whitefield (2008); Bester and Yates (2009); and Whitefield et al. (2010)).

Figure 57 schematically demonstrates how combustion emissions from the engine (i.e., the emissions given by **Equation 23** can result in aviation related climate change and culminating in societal consequences. The challenge in treating non-CO_2 combustion effects lies in developing an adequate scientific understanding of the wide range of impact pathways and resolving the varied atmospheric residence times.

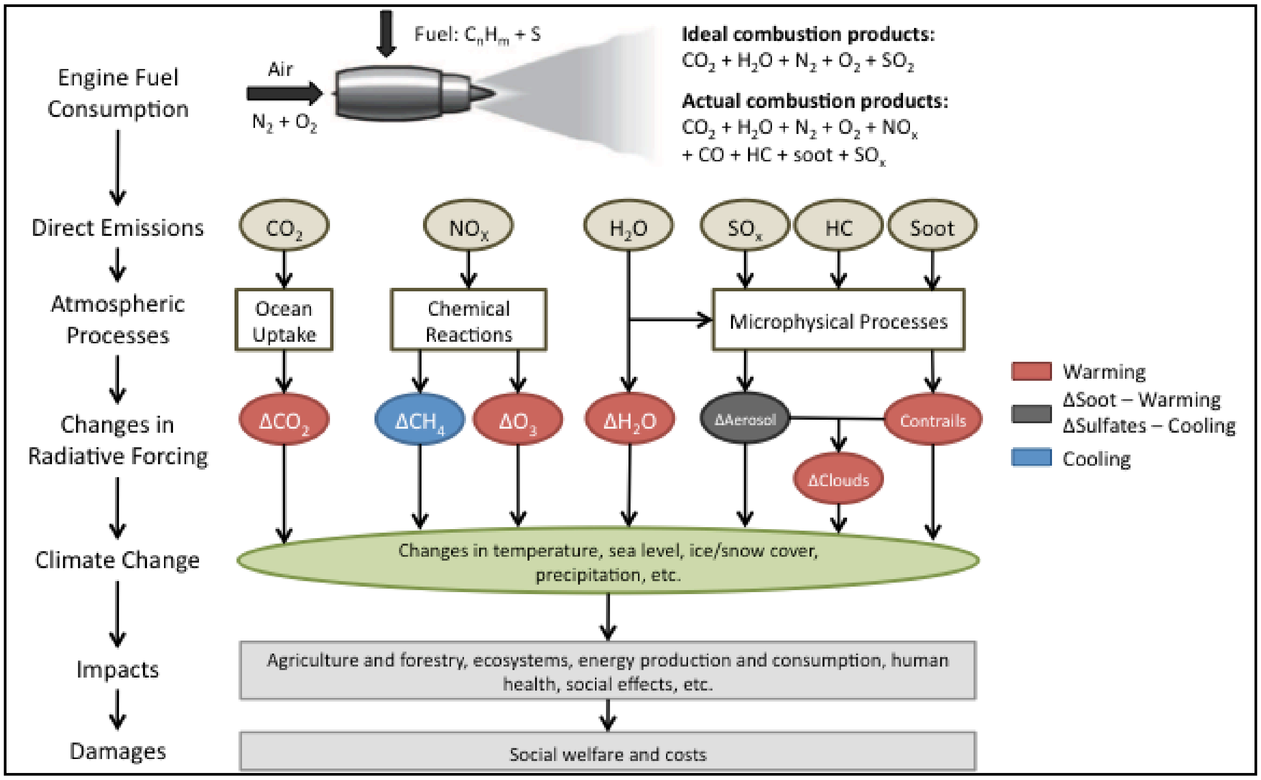


Figure 57. Aviation Climate Change Impacts Pathway (Adapted from Wuebbles et al. (2007) by Stratton (2010))

Carbon dioxide has a warming effect on the atmosphere and a long atmospheric residence time (on the order of centuries). Soot and sulfate aerosols generate atmospheric warming and cooling, respectively, and have residence times on the order of weeks (US EPA, 2009a, 2009b). Additionally, as the hot exhaust gases cool in the surrounding air they could precipitate a cloud of microscopic water droplets called contrails, short for condensation trails. The contrails left by aircraft can subsequently induce the formation of cirrus clouds, called contrail cirrus. Contrails and contrail cirrus last for hours to days and cause atmospheric warming (Minnis et al., 2003). NO_X has several different effects, which result in both warming and cooling. In the months following a pulse of NO_X in the upper atmosphere, ozone production is stimulated causing a short term warming. The NO_X also stimulates the production of additional OH, acting as a sink for methane. The corresponding reduction in methane, which is an important ozone precursor, leads to a long-term reduction in ozone. Both the long-term reduction in methane and ozone are cooling and decay with a lifetime of approximately 11 years (Stevenson et al., 2004; Mahashabde, 2009). Long lived gases become well mixed in the atmosphere; however; short lived emissions can remain concentrated near flight routes, mainly in the northern mid-latitudes; hence, these emissions can lead to regional perturbations to the radiative forcing (Penner et al., 1999).

The life cycle analyst may also be tempted to include estimates of methane and nitrous oxide emissions as they are discussed in the IPCC guidelines and are included in the well-to-tank portion of the LCA; however, as noted by the IPCC, these emissions have considerable

uncertainty in whether or not they are even being produced by modern gas turbine engines (quote from Page 3.56 of (IPCC 2007)).

> *Methane (CH_4) may be emitted by gas turbines during idle and by older technology engines, but recent data suggest that little or no CH_4 is emitted by modern engines. Emissions depend on the number and type of aircraft operations; the types and efficiency of the aircraft engines; the fuel used; the length of flight; the power setting; the time spent at each stage of flight; and, to a lesser degree, the altitude at which exhaust gases are emitted.*

Recent measurements indicate that gas turbines may actually consume atmospheric methane (Miake-Lye, 2010); however, as noted the change in total methane due to aviation must also account for the impact of NO_X emissions. IPCC also notes that modern gas turbine engines produce little to no N_2O emissions (IPCC 1999).

The guidance document (AFLCAWG, 2009) recommended the following in regards to non- CO_2 combustion emissions:

> *Given the uncertainty in estimating jet engine combustion emissions from alternative fuels, the state of the science of aviation climate change, and the lack of metrics to examine the non-CO_2 combustion emissions from aviation* ***, it is recommended that only emissions of CO_2 be included in the combustion stage of the LCA at this time, and that the emissions of CO_2 from bio-derived fuels be tracked separately from the CO_2 emissions from fossil-based fuels.*** *This will allow for a net contribution to atmospheric carbon dioxide to be estimated, while still allowing for data collection would serve multiple purposes. In addition, non-combustion CO_2 emissions should be tracked, to the extent that is practical, for future examination using an appropriate metric.*

Although research is being conducted to examine how non-CO_2 combustion emissions could be compared to the combustion CO_2 emissions for conventional jet fuel and F-T jet fuel blends (Dorbian, 2010; Stratton, 2010), the science is still too immature to include non-CO_2 combustion emissions in a comparative life cycle analysis, such as this. As an example, preliminary studies by Dorbian (2010) and Stratton (2010) show that contrail and contrail cirrus dominate the impact of the other non-CO_2 combustion emissions and aviation climate effects. The effect of changing fuel composition on contrail formation needs to be better understood to make meaningful comparisons of the climate impact of non-CO_2 combustion emissions from conventional and F-T jet fuels. As such, the non-CO_2 combustion emissions are not included in this report.

8.2 Data Quality Assessment

The results of unit process data quality evaluation for LC Stage #5 are provided in Table 126. Because combustion of jet fuel is the most significant process in the jet fuel life cycle, data quality is of particular importance. However, very few parameters are contained within the process. Carbon dioxide emissions are directly based upon carbon content of the fuel, and thus are considered of high quality.

Table 126. LC Stage #5 Unit Process DQI and Significance Check

Process Level	Unit Process	DQI	Life Cycle Significance of Process (%)
1	Jet Fuel Use, Operation	1,3,1,1,2	94.54%

8.3 Results

This section presents the life cycle GHG emissions for Stage 5. Only deterministic results are presented because, as discussed in the Framework and Guidance document, 1) only emissions of CO_2 are considered in the calculation of CO_2e emissions and 2) the jet fuel is assumed to burn completely with all carbon in the fuel converted to CO_2.

The deterministic results for Stage #5 are calculated in the F-T Jet Fuel Spreadsheet Model in sheet S5.Summ, which presents the input flows, output flows (products and co-products) and GHG emissions for this stage. The flows are presented three different ways: normalized to the unit process reference flow, normalized to the stage-level reference flow, and normalized to the functional unit. GHG results are summarized in sheet Summ.Rep.GHG. The total GHG emissions for this stage relative to the stage reference flow and functional unit are presented in this sheet.

Table 127 presents the life cycle GHG emissions for LC Stage 5 in terms of the reference flow for this stage, which is 1 kg of blended jet fuel combusted. This table presents the total emissions of non-biogenic carbon dioxide from operation and construction. The second column in the table presents the actual mass of each constituent emitted. The third through fifth columns present the emissions of each constituent in carbon dioxide equivalents using the global warming potentials for each constituent based on the IPCC 2007, IPCC 2001 and IPCC 1996 estimates, respectively. Although there are slight differences in the composition and properties of the blended F-T jet fuel using the iron versus cobalt catalysts, the differences in CO_2 emissions from the two fuels are indistinguishable based on the standard two significant figures for reporting values used in this report.

Table 127. LC Stage #5 GHG Emissions for Blended Jet Fuel (per kg Blended Jet Fuel Combusted)

Greenhouse Gas (GHG)	Mass of GHG Emitted to Atmosphere (g/kg Blended Jet Fuel)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg Blended Jet Fuel) (IPCC 2007 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg Blended Jet Fuel) (IPCC 2001 GWP)	Mass of GHG Emitted to Atmosphere (g CO_2e/kg Blended Jet Fuel) (IPCC 1996 GWP)
Non-biogenic CO_2 – Operation	3,100	3,100	3,100	3,100
Non-biogenic CO_2 – Construction	0	0	0	0
Non-biogenic CO_2 – Total	3,100	3,100	3,100	3,100

9.0 CO-PRODUCT ALLOCATION PROCEDURE

As discussed in **Section 3.2.5** of the report, several allocation options were identified as reasonable options for allocating emissions between co-products within the system boundary of the ten scenarios modeled. The following describes the procedure used in this study for energy, volume, and mass allocation and system expansion (displacement method).

A third hybrid co-product allocation procedure using a modified system boundary is discussed in **Appendix C** for technical discussion in the scientific community. This hybrid approach may be considered a feasible approach however contradicts the allocation guidance provided in ISO 14044 (2006b) that states "Allocation procedures shall be uniformly applied to similar inputs and outputs of the system under consideration."

9.1 Calculation Procedure for Energy, Volume and Mass Allocation

The allocation procedures for energy, volume and mass were applied to all 10 scenarios. The following text explains the energy allocation procedure using Scenario 2 (84 percent coal, 16 percent biomass, iron-based F-T catalyst, CO_2-EOR Sequestration) as an example. The energy allocation procedure can readily be modified to perform volume and mass allocation, since all three procedures rely on ratios of a physical property.

Energy allocation is performed in five steps. First, the co-products are defined. In LC Stage #3a (CBTL) and LC Stage #3c (CO_2-EOR), there are five co-products produced; three from the CBTL plant (F-T jet fuel, F-T diesel and F-T naphtha) and two from the CO_2-EOR operation (crude oil and natural gas liquids).

Second, the stages involved in the production of the co-products are identified. All the activities in LC Stages #1 through #3 are involved in the production of the five co-products generated in Scenario 2.

Third, the unallocated GHG emissions are summed over the stages involved in the production of the co-products. For Scenario 2, unallocated GHG emissions are summed for the first three stages.

Table 128. Energy Content and Mass Density of Five Co-Products from CBTL and EOR

Product	Energy Content (MJ LHV/kg)	Density (kg/L)
F-T Jet Fuel	44.7	0.751
F-T Diesel	44.3	0.784
F-T Naphtha	44.7	0.676
Crude Oil	44.1	0.873
Natural Gas Liquids	48.8	0.650

Fourth, in energy allocation, the energy content of each co-product stream is determined, the energy content s of all co-product streams are totaled and, for the co-product of interest (F-T jet fuel in this study), the energy content of this stream is divided by the total energy content of all co-product streams. This procedure yields the fraction of the total energy content of all co-product streams that is intrinsic to the co-product of interest. For this study, the energy content and density of each co-product are listed in Table 128. The mass and energy value of each product stream exiting LC Stage #3 are listed in Table 129 relative to the functional unit of 1 MJ LHV blended jet fuel combusted. Using the energy content of each product stream, the percent

contribution of each stream is calculated with respect to the total energy content of all of the co-products. F-T jet fuel accounts for 15.2 percent of the total energy of all co-products produced from LC Stage #3 in Scenario 2.

Table 129. Calculation of Percent Energy Contribution of F-T Jet Fuel with Respect to All Products (Baseline System Boundary, Scenario 2 Example)

Product (Scenario 2 Stream Number)	Mass (grams) per 1 MJ, LHV Blended Jet Fuel Consumed	Energy (MJ) per 1 MJ, LHV Blended Jet Fuel Consumed	Percent Contribution of Products from LC Stage #3 by Energy
F-T Jet Fuel (11)	11	0.49	15.2%
F-T Diesel (5)	7.75	0.34	10.6%
F-T Naphtha (6)	2.04	0.09	2.8%
Crude Oil (9)	50.8	2.24	69.4%
Natural Gas Liquids (10)	1.29	0.06	1.9%
TOTAL:	72.88	3.23	100%

Fifth, the unallocated GHG emissions for the applicable stages are multiplied by the fraction of total energy assigned to the co-product of interest and this becomes the GHG emissions allocated to the co-product of interest. In Scenario 2, the unallocated GHG emissions for LC Stages #1 through #3 are multiplied by the percent energy contribution of F-T jet fuel to yield the CO_2e emissions allocated to F-T jet fuel for LC Stages #1 through #3. The CO_2e emissions for Stages #4 and #5 are calculated separately and added to give the total CO_2e emissions for blended jet fuel.

Table 130 presents the results for the allocation procedure by stage. Since there is uncertainty in the GHG emissions for each stage and for the total of LC Stages #1 through #3, the best estimate of the GHG emission, the 25th percentile of the distribution and the 75th percentile of the distribution for unallocated and allocated GHG emissions are presented in Table 130.

The GHG emissions from LC Stages #1 through #3 have now been allocated to the F-T jet fuel product and the other co-products removed from the study. Although GHG emissions have been allocated to Stages #1 through #3 in this study, it is important to recognize that the "allocated" emissions by unit process or stage do not necessarily represent the actual emissions from a particular unit process or stage associated with a particular product (F-T jet fuel in this instance). From the perspective of interpreting the allocated GHG emissions, *only the sum of the allocated emissions from LC Stages #1 through #3 should be compared to results from other studies*. Assigning allocated emissions to various unit processes or stages is best viewed as a form of accounting. One can assign values to different categories in an accounting ledger as long as the total remains the same. This is true for assigning allocated emissions to the individual unit processes or stages within LC Stages #1 through #3. Caution is also warranted to not use "allocated" unit process profiles without fully understanding how the allocation was performed and how the emissions profile was assigned/distributed to multiple unit processes. Unallocated unit process results should be used when extracting data from this study for use in other studies.

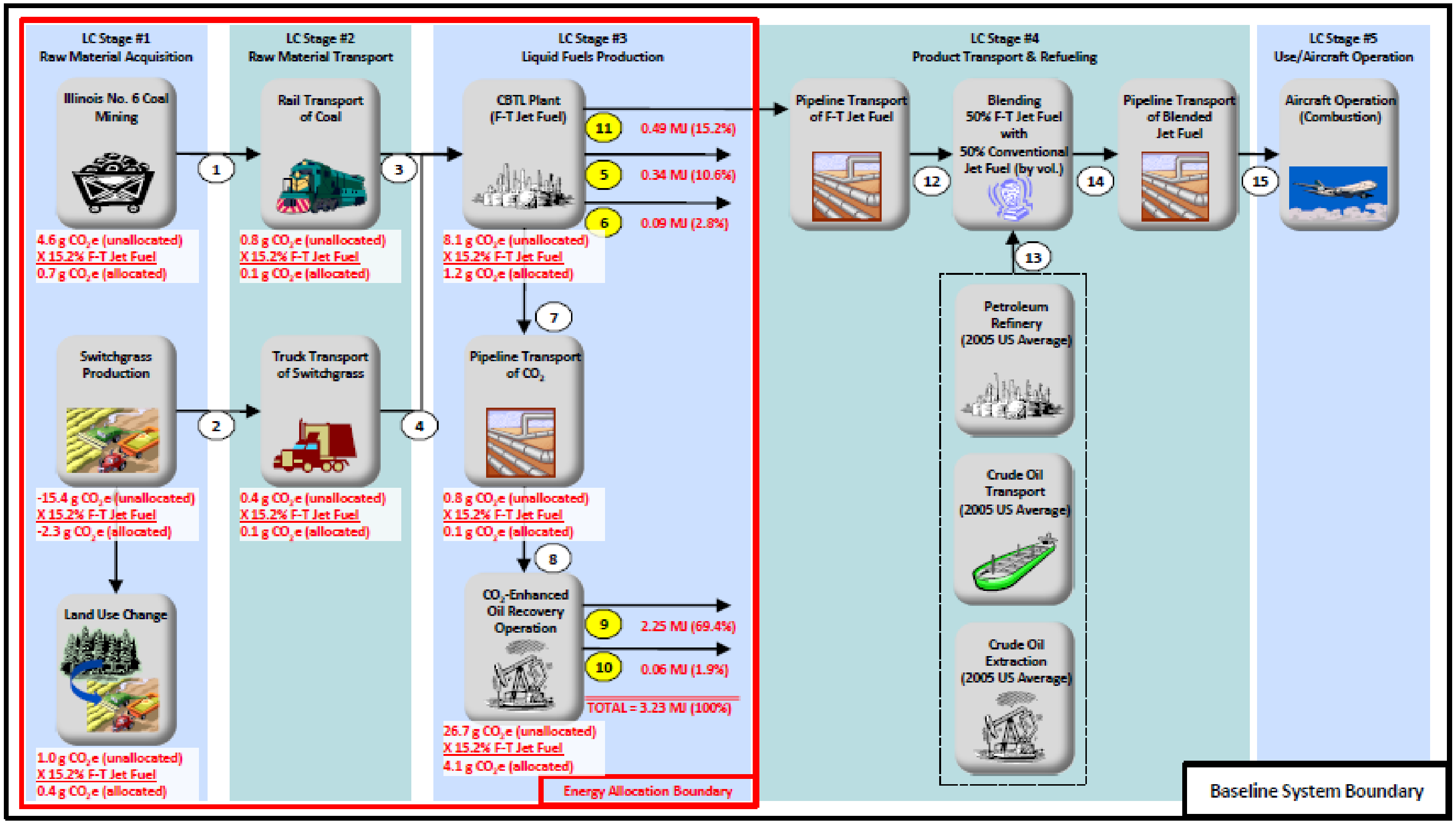
Table 130. Procedure for Allocating GHG Emissions by Percent Energy Contribution of F-T Jet Fuel (Baseline System Boundary, Scenario 2 Example)

Life Cycle Stage	Unit Process	Unallocated Mass of GHG Emitted to Atmosphere ($g\ CO_2e/MJ$, LHV Blended Jet Fuel Consumed) (IPCC 2007 GWP)			% Energy Contribution of F-T Jet Fuel	Allocated Mass of GHG Emitted to Atmosphere ($g\ CO_2e/MJ$, LHV Blended Jet Fuel Consumed) (IPCC 2007 GWP)		
		25%	Best Estimate	75%		25%	Best Estimate	75%
#1: Raw Material Acquisition	Illinois No. 6 Coal Mining	4.2	4.6	5.0	15.2%	0.64	0.71	0.77
	Switchgrass Production	-15.4	-15.4	-15.4	15.2%	-2.3	-2.3	-2.3
	Land Use Change	0.83	1.1	1.5	15.2%	0.13	0.16	0.22
#2: Raw Material Transport	Rail Transport of Coal	0.71	0.81	0.91	15.2%	0.11	0.12	0.14
	Truck Transport of Switchgrass	0.35	0.36	0.37	15.2%	0.054	0.055	0.055
#3: Liquid Fuels Production	CBTL Plant	7.6	8.1	8.5	15.2%	1.2	1.2	1.3
	Pipeline Transport of CO_2	0.74	0.84	0.88	15.2%	0.11	0.13	0.13
	CO_2-EOR Operation	26.5	26.7	27.0	15.2%	4.03	4.06	4.10
TOTAL:	Stages 1-3	26.5	27.1	27.8	15.2%	4.0	4.1	4.2

Figure 58 illustrates the energy allocation procedure for the baseline system boundary for Scenario 2. The same mathematical procedure is repeated for Scenarios 1 and 3 through 5.

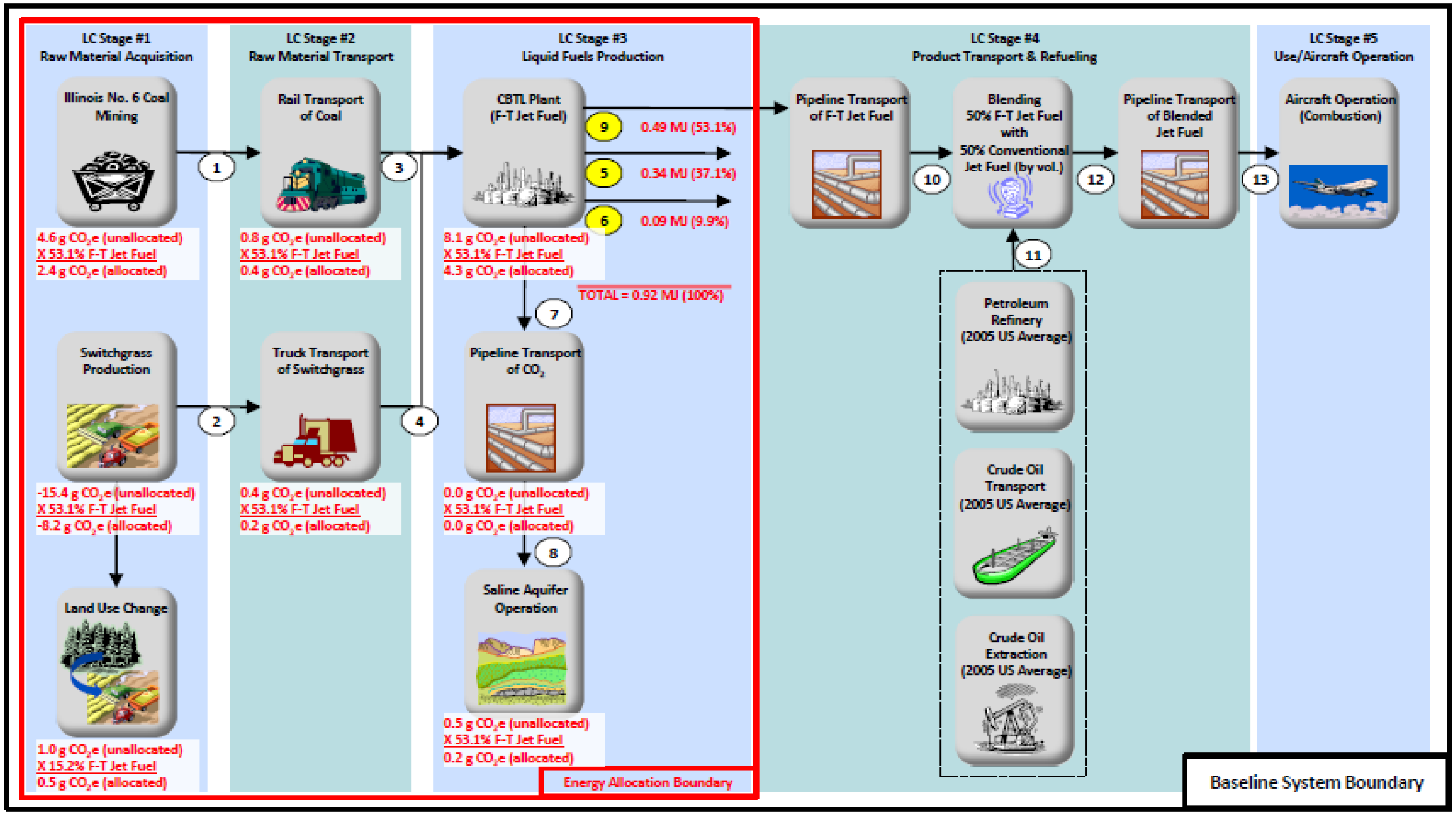
Essentially the same mathematical procedure is also used for Scenarios 6 through 10 once the list of co-products is adjusted to reflect only the three products from the CBTL plant because the CO_2 is sequestered in a saline aquifer that does not produce crude oil or natural gas liquids. The resulting percent energy contribution of the F-T jet fuel for the baseline system boundary for Scenario 7 (same as Scenario 2 except injection in a saline aquifer is used as the carbon management strategy instead of the CO_2-EOR operation) is 53.1 percent. The total GHG emissions for LC Stages #1 through #3 is 0.11 g CO_2e/MJ, LHV blended jet fuel combusted and the GHG emissions allocated to F-T jet fuel is 0.059 g CO_2e/MJ, LHV blended jet fuel combusted (IPCC 2007 GWP). Figure 59 illustrates the energy allocation procedure for the Baseline System Boundary for Scenario 7.

The procedures for allocating by volume and mass are similar to the procedure for energy allocation. In volume allocation, the volume of each co-product stream is calculated and the fraction of the volume of F-T jet fuel relative to the volume of all co-product streams is used to allocate the GHG emissions for LC Stages #1 through #3. In mass allocation, the mass of each co-product stream is calculated and the fraction of the mass of F-T jet fuel relative to the mass of all co-product streams is used to allocate the GHG emissions for LC Stages #1 through #3.



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (wet)	60	grams	6	F-T Naphtha	2.0	grams	11	F-T Jet Fuel	11	grams
2	Switchgrass (dry)	9.5	grams	7	Supercritical CO_2	84	grams	12	F-T Jet Fuel	11	grams
3	Illinois No. 6 Coal (wet)	60	grams	8	Supercritical CO_2	83	grams	13	Conv. Jet Fuel	12	grams
4	Switchgrass (dry)	9.5	grams	9	Crude Oil	51	grams	14	Blended Jet Fuel	23	grams
5	F-T Diesel	7.7	grams	10	Natural Gas Liquids	1.3	grams	15	Blended Jet Fuel	23	grams

Figure 58. Energy Allocation Procedure (Scenario 2 Example)



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (wet)	60	grams	6	F-T Naphtha	2.0	grams	11	Conv. Jet Fuel	12	grams
2	Switchgrass (dry)	9.5	grams	7	Supercritical CO_2	84	grams	12	Blended Jet Fuel	23	grams
3	Illinois No. 6 Coal (wet)	60	grams	8	Supercritical CO_2	83	grams	13	Blended Jet Fuel	23	grams
4	Switchgrass (dry)	9.5	grams	9	F-T Jet Fuel	11	grams				
5	F-T Diesel	7.7	grams	10	F-T Jet Fuel	11	grams				

Figure 59. Energy Allocation Procedure (Scenario 7 Example)

Table 131 presents the percent of the F-T jet fuel stream on an energy, volume and mass basis for each scenario. For a given scenario, the percent assigned to F-T jet fuel is similar whether energy, volume or mass is used as the basis. Thus, there will be little difference in the results for energy, volume and mass allocation. Since all the co-products are energy products, the results of only energy allocation (not volume or mass allocation) are presented in the remainder of this report, along with the results of displacement allocation.

Table 131. Percent Contribution of F-T Jet Fuel to the Total Co-Product Streams on an Energy, Volume and Mass Basis for Each Scenario

Scenario	System Boundary	Energy Allocation	Volumetric Allocation	Mass Allocation
1	Baseline	15%	17%	15%
2	Baseline	15%	17%	15%
3	Baseline	15%	17%	15%
4	Baseline	17%	18%	17%
5	Baseline	23%	25%	23%
6	Baseline	53%	53%	53%
7	Baseline	53%	53%	53%
8	Baseline	53%	53%	53%
9	Baseline	58%	58%	58%
10	Baseline	80%	79%	80%

9.2 Calculation Procedure for Displacement Allocation

In the displacement method, a co-product is assumed to displace a product with the same function that is produced by a different process, typically at an unrelated facility (Allen, 2009). A summary of each of the substitute production process used in this study is provided in Table 132.

The system expansion/displacement method allocation procedure is applied to all 10 Scenarios. The following text explains the procedure used for both system boundaries using Scenario 7 (84 percent Coal, 16 percent Biomass, Iron-based F-T Catalyst, Sequestration in a Saline Aquifer).

Displacement allocation is performed in five steps. First, the co-products are defined. In LC Stage #3a, there are three co-products produced (F-T jet fuel, F-T diesel and F-T naphtha).

Second, the stages involved in the production of the co-products are identified. All the activities in LC Stages #1 through #3 are involved in the production of the three co-products generated in Scenario 7.

Third, the unallocated GHG emissions are summed over the stages involved in the production of the co-products. For Scenario 7, unallocated GHG emissions are summed for the first three stages.

Fourth, for each co-product other than the co-product of interest, the mass flow of each co-product stream is determined and this mass flow is multiplied by the GHG emissions per unit mass from the substitute production process. This gives the GHG emissions for the substitute production process for each co-product (other than the co-product of interest). These GHG emissions are summed to give the total GHG emissions for displacement. For Scenario 7, Table 133 lists the two co-products displaced from the baseline system boundary, the substitute cradle-

to-gate GHG emissions applied, and the resulting GHG emissions for the two co-products to be used in the displacement.

Table 132. Summary of Substitute Production Processes Use in the System Expansion / Displacement Allocation Procedure

Co-Product	Substitute / Displacement Product				
	Displaced Product	Value	Units	Description	Source
F-T Diesel	Conventional Diesel Fuel	0.82	kg CO_2e/ kg (2007 IPCC GWP)	2005 US average for conventional diesel fuel sold or distributed (petroleum baseline). Cradle-to-gate life cycle ending at the exit of the petroleum refinery.	NETL 2008
F-T Naphtha	Conventional Naphtha	0.58	kg CO_2e/ kg (2007 IPCC GWP)	2005 US average for conventional kerosene-based jet fuel/naphtha. Cradle-to-gate life cycle ending at the exit of the petroleum refinery.	NETL 2008
Crude Oil (CO_2-EOR)	US Domestic Crude Oil (2005 Average)	0.29	kg CO_2e/ kg (2007 IPCC GWP)	2005 US domestic crude oil. Cradle-to-gate life cycle profile for crude oil extraction only.	NETL 2009b
Natural Gas Liquids	Natural Gas Liquids	0.12	kg CO_2e/ kg (2007 IPCC GWP)	2008 US domestic offshore natural gas. Cradle-to-gate life cycle profile for natural gas extraction only.	NETL 2010a

Fifth, the total GHG emissions for displacement are subtracted from the unallocated GHG emissions for the applicable stages. The displacement calculations were accomplished at the stage level as follows. First, the total GHG emissions for displacement are stored in the variable SUM_{disp}. Second, the absolute value of the unallocated GHG emissions for each the susbstage in Stage #1 through #3 was calculated, summed and stored in the variable $ABSSUM_{unalloc}$. Third, if the variable $GHG_{unalloc\_x}$ stores the unallocated GHG emissions for substage #x, then the allocated emissions for substage #x (GHG_{alloc_x}) are calculated using Equation 24:

Equation 24: $GHG_{alloc\_x} = GHG_{unalloc\_x} – ABS(GHG_{unalloc\_x}) * SUM_{disp} / ABSSUM_{unalloc}$

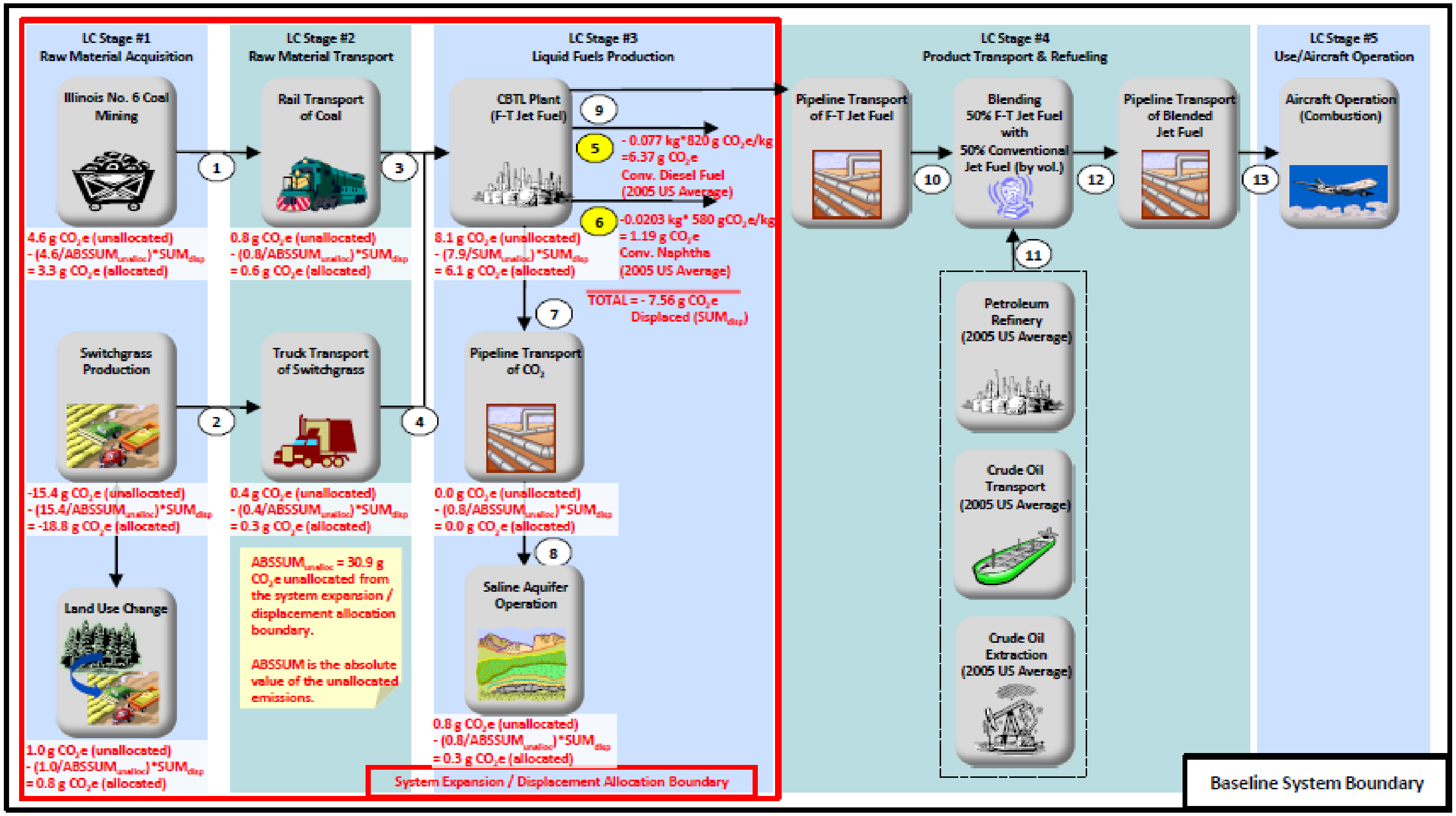
This equation subtracts a fraction of the total GHG emissions to be displaced (SUM_{disp}) from the unallocated emissions for each substage in Stages #1 through #3. Figure 60 illustrates the displacement allocation procedure for Scenario 7.

Table 133. Calculation of Displacement Values for Co-Products from CBTL Plant Operation (Baseline System Boundary, Scenario 7 Example)

Product (Scenario 7 Stream Number)	Mass (grams) per 1 MJ, LHV Blended Jet Fuel Consumed	Cradle-to-Gate GHG Emissions for Substitute Production Process (g CO_2e/g product (2007 IPCC GWP)	GHG Emissions Displaced (g CO_2e/1MJ, LHV Blended Jet Fuel Consumed (2007 IPCC GWP)
F-T Diesel (5)	7.75	0.82	6.37
F-T Naphtha (6)	2.04	0.58	1.19
TOTAL:	9.79	N/A	7.56

At this point, the GHG emissions from LC Stages #1 through #3 have been allocated to the F-T jet fuel product, and the other co-products have been removed from the study. While the GHG emissions have been allocated by substage, it is important to recognize that the "allocated" emissions by substage do not represent the actual emissions from a particular substage. This situation is analogous to the situation discussed for performing energy allocation in the previous section. From the perspective of results interpretation, only the sum of the allocated emissions from LC Stages #1 through #3 (within the allocation boundary) can be compared to results from other studies unless the emissions were distributed across all of the substages in a manner similar to that done in this study. Assigning allocated emissions to substages is best viewed as a form of accounting. One can assign values to different categories in an accounting ledger as long as the total remains the same. This is true for assigning allocated emissions to the individual substages within the allocation boundary. Caution is also warranted to not use "allocated" substage profiles without fully understanding how the allocation was performed and how the emissions profile was assigned/distributed to multiple unit processes. Unallocated substage results should be used when extracting data from this study for use in other studies.

The use of displacement allocation in support of this study introduces a degree of uncertainty with respect to life cycle GHG emissions. Key to considering displacement allocation is the role of naphtha and uncertainties in the naphtha market. Herein, the effects of producing naphtha, in quantities indicated within this study, on global refinery operations, is uncertain. Similarly, the effects of introducing additional naphtha to the market would have unknown consequences in terms of industry reaction. As a result, the eventual fate/eventual use of naphtha produced within this study is therefore difficult or impossible to determine with a high degree of certainty. However, this limitation is not expected to be sufficient to remove displacement as a choice for allocation procedure from this study.



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (wet)	60	grams	6	F-T Naphtha	2.0	grams	11	Conv. Jet Fuel	12	grams
2	Switchgrass (dry)	9.5	grams	7	Supercritical CO_2	84	grams	12	Blended Jet Fuel	23	grams
3	Illinois No. 6 Coal (wet)	60	grams	8	Supercritical CO_2	83	grams	13	Blended Jet Fuel	23	grams
4	Switchgrass (dry)	9.5	grams	9	F-T Jet Fuel	11	grams				
5	F-T Diesel	7.7	grams	10	F-T Jet Fuel	11	grams				

Figure 60. System Expansion / Displacement Allocation Procedure (Baseline System Boundary, Scenario 7 Example)

10.0 LIFE CYCLE GHG RESULTS

This section reviews results from the full fuel cycle for F-T jet fuel, from feedstock production and extraction in LC Stage #1 to blended jet fuel combustion in LC Stage #5 for each scenario. For a review of results specific to each LC Stage, please see the results sections of **Section 4** through **Section 8**. This section presents life cycle results for the baseline system boundary, as described in **Section 3**. For a discussion of results relevant to the modified system boundary, please refer to **Appendix C**. Results from each of the 10 Scenarios included in this study are independently documented below, as if the report were to contain only one scenario. The purpose of this format is to illustrate a rough guideline for documenting summary level results to decision makers. For a critical comparison of the results presented in this section, including discussion of critical trends and observations, please refer to **Section 11**.

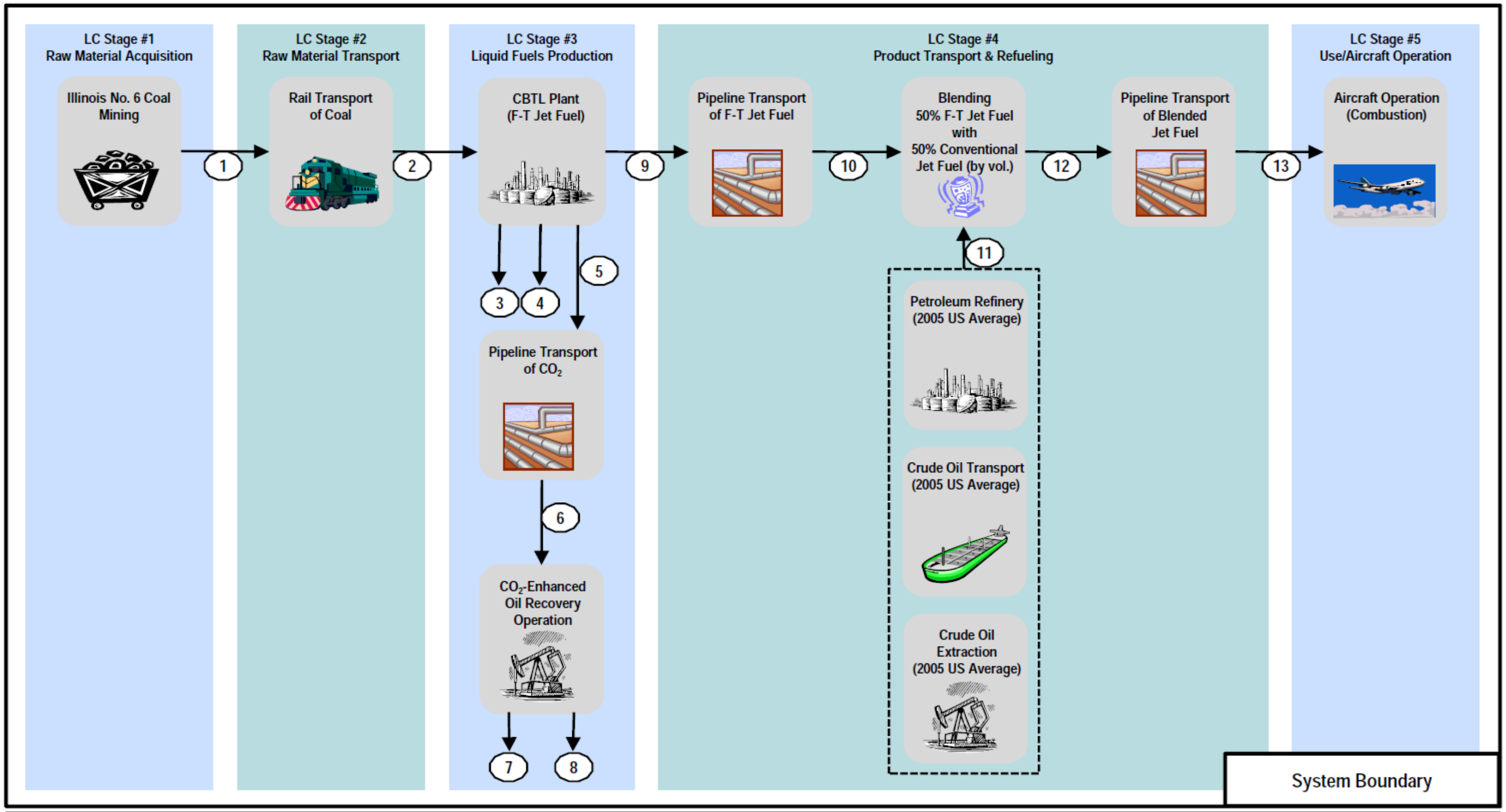
10.1 Scenario 1: 0 Percent Switchgrass, Iron F-T Catalyst, EOR

10.1.1 Scenario Overview

Scenario 1 was designed to evaluate F-T fuels derived solely from coal feedstock. Like other scenarios, Scenario 1 assesses a 1:1 blend F-T and conventional jet fuel (US Average) over a period of 30 years. Illinois No. 6 sub-bituminous coal feedstock is processed at a CBTL facility located in Northern Missouri. The F-T process employed at the facility uses an iron catalyst without autothermal reforming, and with 91 percent flue gas carbon capture. The F-T process produces a combination of F-T jet fuel (52.9 percent by energy), F-T diesel (37.3 percent by energy), and F-T naphtha (9.83 percent by energy). Captured carbon dioxide is conveyed via a 775 mile pipeline to the Permian Basin in Texas, where it is used as an injectant in support of CO_2 EOR, and eventually sequestered. The EOR process also results in the production of crude oil and natural gas liquids. Finally, the F-T jet fuel is conveyed via pipeline from the CBTL Facility to a separate blending facility, located at the Woods River Refinery in Illinois. Here it is blended with conventional jet fuel and shipped via pipeline to Chicago O'Hare Airport. Alternatively, the blended fuel may be shipped via a combination of pipeline and tanker truck to Chicago O'Hare and smaller regional airports. Scenario 1 is most similar to Scenario 6, which also relies solely on coal as feedstock, and uses an iron F-T catalyst. Table 134 provides an overview of key values for Scenario 1.

Table 134. Scenario 1 Overview

Item		Scenario Property		
Study Properties				
Functional Unit		1 MJ of Blended F-T Jet Fuel Consumed		
Blended F-T Jet Fuel		4,010 MJ/bbl		
F-T Jet Fuel		50 percent of final product (by volume)		
Conventional Jet Fuel (US Average)		50 percent of final product (by (volume)		
Temporal Boundary		30 years		
CBTL Facility Properties				
Plant Location		Northern Missouri		
Daily Production Capacity		30,000 bbl/d		
F-T Catalyst Type		Iron		
Autothermal Reforming		No		
Tail Gas Recycle		Yes		
Carbon Capture		91 percent in flue gas		
Optimized for Maximum F-T Jet Fuel Production		No		
Item	**Value**	**Units**	**Value**	**Units**
Energy Feedstock Inputs to CBTL Facility				
Coal, Illinois No. 6	12,728	short tons/day	100%	percent by energy
Biomass, Switchgrass	0	short tons/day	0%	percent by energy
Product Outputs from CBTL Plant				
CBTL Plant Liquid Product Output	30,000	bbl/d	100%	percent by energy
CBTL Plant F-T Jet Fuel Production	15,939	bbl/d	52.9%	percent by energy
CBTL Plant F-T-Diesel Fuel Production	10,769	bbl/d	37.3%	percent by energy
CBTL Plant F-T Naphtha Production	3,292	bbl/d	9.83%	percent by energy
Carbon Management Strategy: CO_2-Enhanced Oil Recovery (CO_2-EOR)				
Storage Location	Permian Basin, TX		775	miles from CBTL Facility
Carbon Dioxide Sequestered	15,777	short tons/day	99.5%	percent of CO_2 received
Crude Oil Production	63,440	bbl/d	97.3%	percent by energy
Natural Gas Liquids Production	2,927	bbl/d	2.7%	percent by energy
Carbon Management Strategy: Saline Aquifer				
Storage Location	N/A		N/A	N/A
Carbon Dioxide Sequestered	N/A	N/A	N/A	N/A
Product Transport to Airport				
F-T Jet Fuel Pipeline Transport to Wood River, Il Refinery	21,595	bbl/d	225	miles
Blended F-T Jet Fuel Pipeline Transport to Chicago O'Hare Airport	22,346	bbl/d	245	miles



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (dry)	59.3	g/MJ LHV	6	Supercritical CO_2	83.1	g/MJ LHV	11	Conv. Jet Fuel	11.8	g/MJ LHV
2	Illinois No. 6 Coal (dry)	59.3	g/MJ LHV	7	Crude Oil	50.8	g/MJ LHV	12	Blended Jet Fuel	22.8	g/MJ LHV
3	F-T Diesel	7.75	g/MJ LHV	8	Natural Gas Liquids	1.29	g/MJ LHV	13	Blended Jet Fuel	22.8	g/MJ LHV
4	F-T Naphtha	2.04	g/MJ LHV	9	F-T Jet Fuel	11.0	g/MJ LHV	14			
5	Supercritical CO_2	83.7	g/MJ LHV	10	F-T Jet Fuel	11.0	g/MJ LHV	15			

Figure 61. Scenario 1: System Boundary and Major Flows (g/MJ Jet Fuel Combusted, LHV)

10.1.2 Life Cycle GHG Results

Lifecycle GHG results are presented below for the deterministic analysis using the best estimate for each modeling parameter, probabilistic uncertainty analysis using the defined uncertainty ranges and probability distributions sampled approximately 2,000 times using a Monte Carlo simulation, and sensitivity analysis to determine the key modeling parameters within the life cycle with greatest influence on the results.

10.1.2.1 Deterministic Analysis Results

Allocated results are tabulated in terms of life cycle sub-categories in Table 135 for both energy allocation and system expansion/displacement allocation method. Total unallocated CO_2e emissions are also provided along with each allocated result to assist understanding of the effect of allocation on each final result. The unallocated results do not represent the life cycle GHG result for 1 MJ of blended F-T Jet Fuel consumed. Unallocated results represent the total GHG emissions released to the atmosphere to produce the suite of co-products produced within the study boundary.

The deterministic analysis results in a 3 percent reduction in life cycle GHG emissions in comparison to a conventional jet fuel baseline of 87.4 g CO_2e/MJ jet fuel combusted, LHV when allocated by energy. Allocation of the co-products using the displacement method results an 11 percent increase in the life cycle GHG profile compared to conventional jet fuel baseline. The opposing results draw attention to the effect of co-product allocation procedures on the interpretation of life cycle analysis results. The deterministic results of this study show that the life cycle GHG profile for Scenario 1 is between 3 percent below to 11 percent above the conventional jet fuel baseline.

Table 135. Scenario 1 Deterministic Analysis Results (Using IPCC 2007 GWP)

Life Cycle Stage Sub-categories	Unallocated CO_2e Emissions[1]		CO_2e Emissions Allocated by Energy		CO_2e Emissions Allocated by Displacement	
	g/MJ	%	g/MJ	%	g/MJ	%
LC Stage 1a: Illinois No. 6 Coal Acquisition	5.2	4.3%	0.8	0.9%	2.4	2.4%
LC Stage 2a: Coal Transport	0.9	0.7%	0.1	0.1%	0.4	0.4%
LC Stage 1b: Switchgrass Biomass Production	0	0.0%	0	0.0%	0	0.0%
LC Stage 1c: Direct Land Use	0	0.0%	0	0.0%	0	0.0%
LC Stage 1c: Indirect Land Use	0	0.0%	0	0.0%	0	0.0%
LC Stage 2b: Switchgrass Transport	0	0.0%	0	0.0%	0	0.0%
LC Stage 3a: CBTL Facility	8.4	7.0%	1.3	1.5%	3.9	4.0%
LC Stage 3b: Supercritical CO_2 Transport	0.8	0.7%	0.1	0.1%	0.4	0.4%
LC Stage 3c: Enhanced Oil Recovery (EOR)	26.7	22.1%	4.1	4.8%	12.5	12.7%
LC Stage 3d: Supercritical CO_2 Sequestration	0	0.0%	0	0.0%	0	0.0%
LC Stage 4: F-T Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 4: Conventional Jet Fuel Life Cycle	6.9	5.7%	6.9	8.1%	6.9	7.0%
LC Stage 4: Blended Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 5: Jet Fuel Use	71.4	59.2%	71.4	84.1%	71.4	72.7%
Life Cycle Total:	120.6	100.0%	84.9	100.0%	98.2	100.0%

1. Unallocated results represent all co-products produced within the system boundary therefore do not represent the life cycle GHG results for 1 MJ of blended F-T jet fuel consumed. The unallocated results are presented only to illustrate the effect of allocation.

Results by life cycle stage contribution show that fuel combustion (use phase) accounts for the majority of life cycle GHG emissions for both energy allocation (84 percent of total life cycle emissions) and displacement (73 percent of total lifecycle emissions) respectively. Excluding the use phase, the upstream life cycle stage with the next highest life cycle GHG contribution differs by the method of co-product allocation. The next largest contributor for the allocation by energy method is the conventional jet fuel production life cycle followed by EOR. Allocation by displacement method results in enhanced oil recovery operation followed by conventional jet fuel production life cycle as significant contributors. Interestingly, the CBTL facility contributes only 1.3 percent to 3.9 percent to the total life cycle GHG profile, depending on method of allocation.

10.1.2.2 Probabilistic Uncertainty Analysis Results

Presents summary statistics for probabilistic CO_2e emissions for Scenario 1 (0 percent switchgrass, iron F-T catalyst, normal product slate, and EOR) along with the "best estimate" (i.e., the deterministic result) presents the probabilistic results in a "box and whisker" plot.

Table 136 presents summary statistics for the resulting CO_2e emissions for Scenario 1 along with the "best estimate," which is the deterministic result. CO_2e emissions are presented using energy allocation and displacement. The minimum value, 25th percentile, median (50th percentile), 75th percentile and maximum value are presented for each probabilistic result. Also presented in Table 136 are statistics for the "combined" result. The "combined" result was generated by combining the probabilistic results for the two primary probabilistic results (i.e., the result for energy allocation and displacement allocation).

The probability distributions were generated for emissions allocated by energy and displacement by executing the F-T Jet Fuel Spreadsheet Model 2,000 times with values randomly selected from the distribution for each uncertain variable, during each iteration of the model. The combined result was obtained by randomly choosing results from either energy or displacement allocation at each iteration, and using the resulting 2,000 values to create the probability distribution for the combined result. In Table 141, the best estimate for the combined result is the average of the best estimates for energy and displacement allocation.

Figure 62 presents the probabilistic results in a "box and whisker" plot, for Scenario 1. In these plots, the bottom line of the box is the 25th percentile, the middle line is the median and the top line of the box is the 75th percentile. The outlier bars (the "whiskers") show minimum and maximum. The "x" marker indicates the best estimate and the solid line is the CO_2e emissions for conventional jet fuel.

Interestingly, the performance viability of Scenario 1 depends on the type of allocation that is applied within the LCI. As shown, allocation by energy results in a median CO_2e emissions value of 85.0 g CO_2e/MJ LHV, which is approximately 2.7 g CO_2e/MJ LHV less than emissions for conventional jet fuel. However, when displacement allocation is applied to the same study parameters and modeling choices, the result is a median CO_2e emissions value that exceeds conventional jet fuel emissions by 10.8 g CO_2e/MJ LHV. As shown, the distribution for the combined result spans the conventional jet fuel emissions value, but approximately 75 percent of the distribution exceeds the conventional jet fuel emissions value. This result highlights the sensitivity to modeling parameters and may identify areas within the life cycle that require additional monitoring and verification to validate the life cycle results.

Table 136. Scenario 1 Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

Quantity	CO_2e Emissions Allocated by Energy (g CO_2e/MJ LHV)	CO_2e Emissions Allocated by Displacement (g CO_2e/MJ LHV)	Combined CO_2e Emissions (g CO_2e/MJ LHV)
Minimum	84.4	95.7	84.4
25th Percentile	84.8	97.6	84.9
Median	85.0	98.2	85.3
75th Percentile	85.1	98.9	98.2
Maximum	85.6	101.0	101.0
Best Estimate	84.9	98.2	91.6
Conventional Jet Fuel	87.4	87.4	87.4

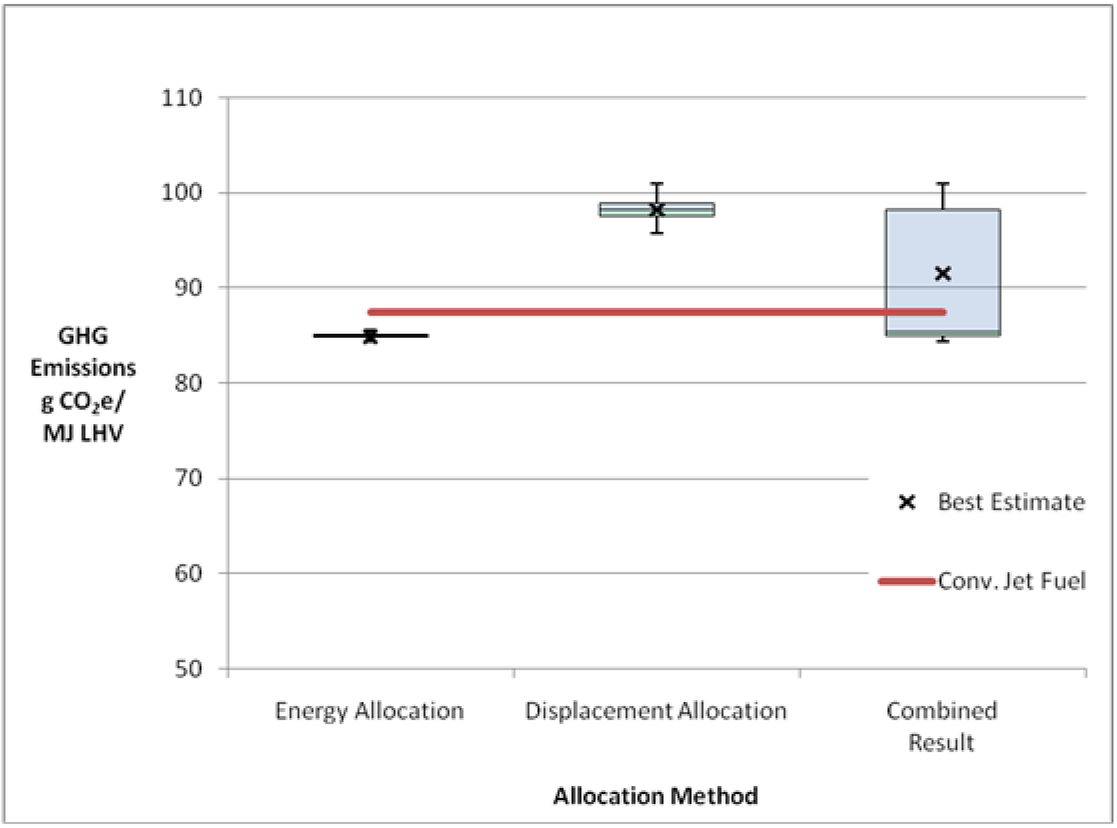


Figure 62. Scenario 1 Box and Whisker Plot of Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

10.1.2.3 Sensitivity Analysis Results

Sensitivity analysis results were calculated for both co-product allocation procedures (energy allocation and displacement method) by adjusting each modeling parameter independently between the minimum and maximum values to determine the effect on the final life cycle GHG result. The 24 modeling parameters with the greatest effect on the results was determined and ranked from highest to lowest based on their absolute difference. The results are reported in both tabular and graphical form in Table 137 and Figure 63 for the energy allocation results and Table 138 and Figure 64 for the displacement method results. All results are reported based on the IPCC 2007 global warming potentials.

Table 137. Scenario 1 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	84.6	85.2	0.563
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	85.1	84.8	0.284
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.7	85	84.8	0.231
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	84.8	85	0.206
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	84.8	85	0.171
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air_3c	kg/kg	0.005	0	0.01	84.9	85	0.126
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	84.9	85	0.117
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	84.9	85	0.106
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	84.9	85	0.0902
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	Mi	200	150	250	84.9	85	0.0678
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	84.9	84.9	0.0527
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	84.9	84.9	0.0346
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	84.9	84.9	0.0325
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	84.9	84.9	0.027

Table 137. Scenario 1 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	Mi	775	698	853	84.9	84.9	0.0255
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	84.9	84.9	0.0227
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	84.9	84.9	0.00636
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	0	0	0	84.9	84.9	0
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS_3d	tonne/tonne	0.005	0	0.01	84.9	84.9	0
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	84.9	84.9	0
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	84.9	84.9	0
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	84.9	84.9	0
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	84.9	84.9	0
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	0	0	0	84.9	84.9	0

Table 138. Scenario 1 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	99.1	97.3	1.87
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.7	98.9	97.4	1.52
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	97.5	98.9	1.35
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	97.6	98.8	1.12
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air_3c	kg/kg	0.005	0	0.01	97.8	98.6	0.831
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	97.9	98.5	0.563
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	Mi	200	150	250	98	98.4	0.446
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	98	98.4	0.375
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	98	98.4	0.346
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	98.3	98.1	0.214
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	98.1	98.3	0.178
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	Mi	775	698	853	98.1	98.3	0.168
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	98.1	98.3	0.149
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	98.2	98.3	0.117
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	98.1	98.2	0.106

Table 138. Scenario 1 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/MJ Blended Jet Fuel Consumed)		
			Best Estimates	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	98.2	98.2	0.0418
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	98.2	98.2	0.0346
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	0	0	0	98.2	98.2	0
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS_3d	tonne/tonne	0.005	0	0.01	98.2	98.2	0
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	98.2	98.2	0
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	98.2	98.2	0
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	98.2	98.2	0
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	98.2	98.2	0
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	0	0	0	98.2	98.2	0

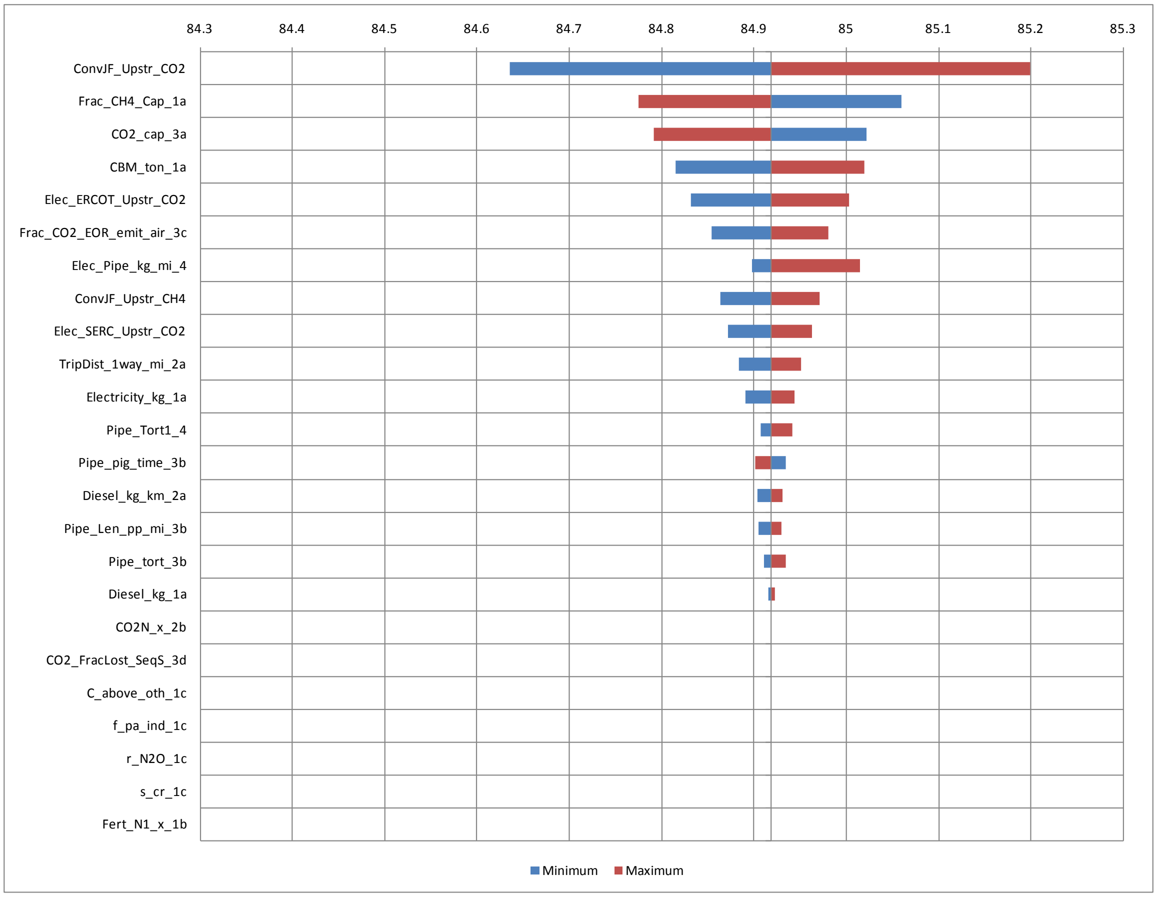


Figure 63. Scenario 1 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

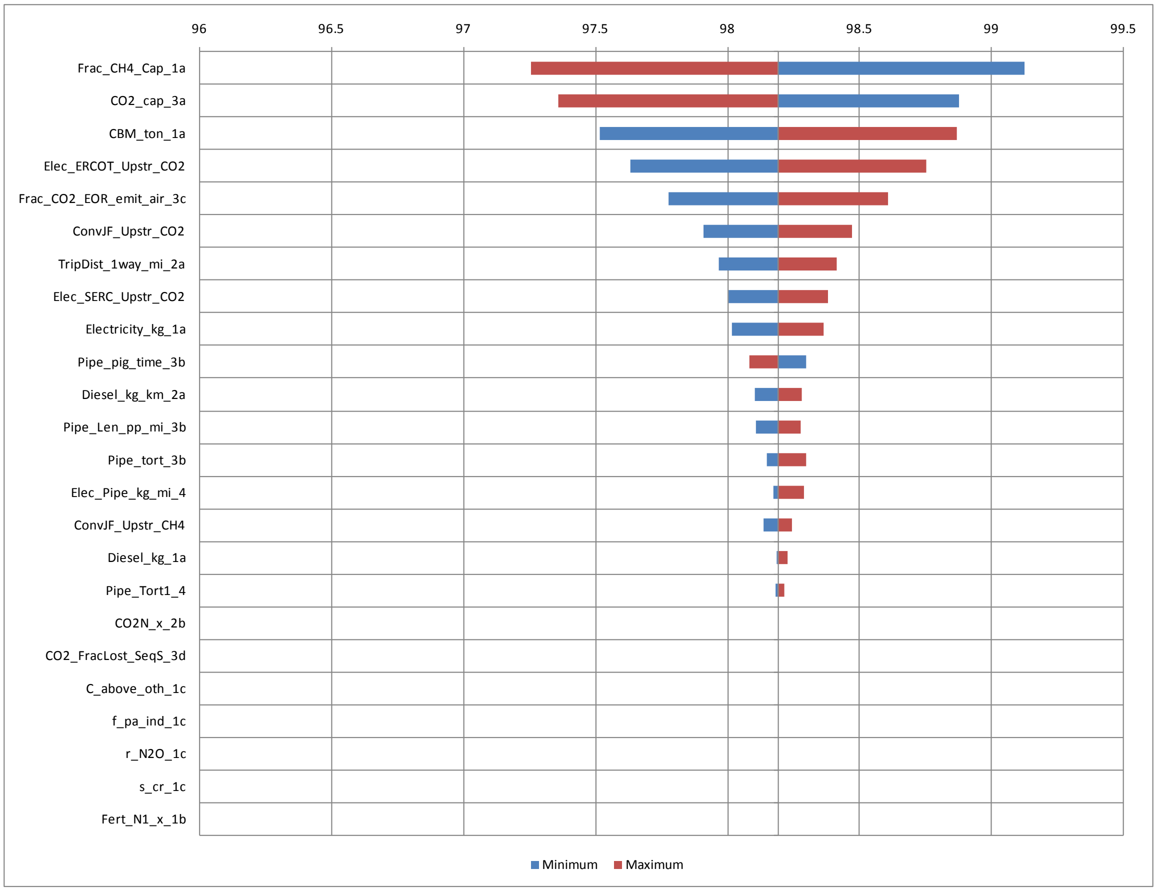


Figure 64. Scenario 1 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

10.1.3 Data Limitations

In terms of broader study limitations, the model boundaries and modeling choices contained in this scenario inform the following study limitations, which should be considered when interpreting final results and conclusions generated from this study:

- **Mine and Mine Methane Emissions:** this scenario presumes that Illinois No. 6 sub-bituminous coal from an underground longwall mine would be used, having an average methane emission rate of 150 scf CH_4/ton with 40 percent capture. Use of an alternative coal type, mine type, methane emission rate, or methane capture rate could increase or decrease mine and mine methane related GHG emissions.
- **CBTL Facility Carbon Capture Rate:** the rate of carbon capture at the F-T facility used for this scenario is 91 percent, which is expected to be a conservative estimate of actual carbon capture rates. However, carbon capture facilities have not been widely implemented at the commercial scale. Therefore, a higher or lower carbon capture rate may apply to some future studies. Increases or decreases in this rate would result in concurrent increases or decreases in life cycle GHG emissions.

- **CBTL Facility Modeling Scenarios:** in order to model the F-T facility, output from a separate ASPEN model was incorporated into the life cycle model used for this study. As a result, the F-T facility model included in this study is static: the workings of the F-T facility cannot be updated or altered to evaluate different F-T facility parameters and setups, without performing substantial additional analysis. The F-T facility results from this study represent specific assumptions, as documented in **Section 6**, and are not necessarily representative of all potential F-T Facility designs.
- **EOR CO_2 Leakage Rates:** this scenario incorporates CO_2 leakage rates of less than one percent. However, actual leakage rates have not been extensively documented, and are expected to be difficult to monitor. Increases in CO_2 leakage rates could result in concurrent increases in life cycle GHG emissions.
- **Pre-Existence of Infrastructure:** some of the infrastructure needed within the boundary of this study, such as a pipeline network suitable for transferring F-T Jet Fuel to the blending facility, was assumed to be pre-existing. No GHG emissions penalty was included for this infrastructure.
- **Comparative Study Results:** the purpose of this study is to provide a comparative evaluation of alternative fuels against baseline 2005 conventional petroleum jet fuel production and use. Results provided for this scenario reflect life cycle emissions from alternative jet fuel production in comparison to that baseline. However, results from this scenario are not intended to provide absolute GHG emissions values; results from this study should be used with caution, when comparing to life cycle analyses having different baseline assumptions and study goals.

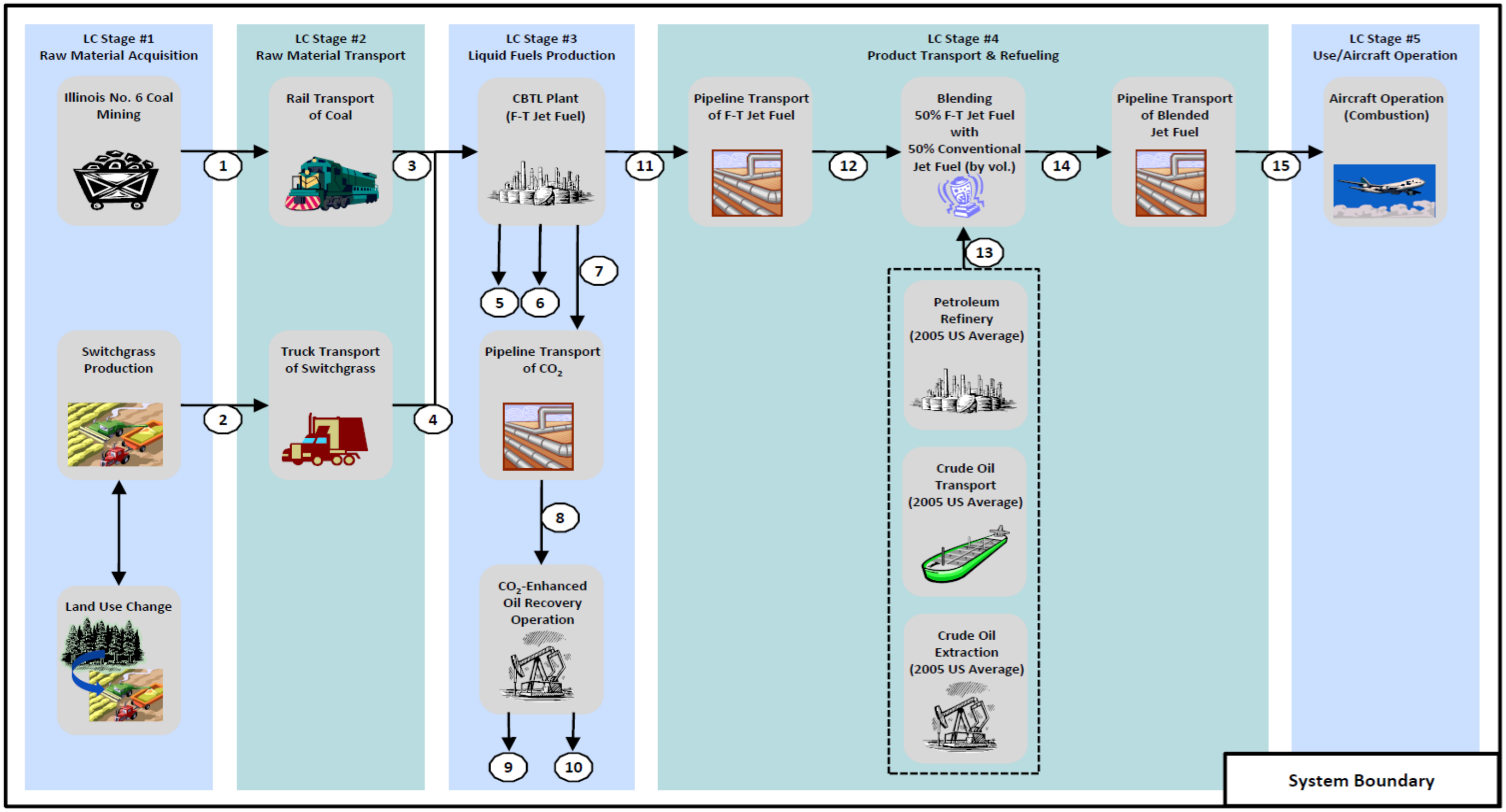
10.2 Scenario 2: 16 Percent Switchgrass, Iron F-T Catalyst, EOR

10.2.1 Scenario Overview

Scenario 2 was designed to evaluate F-T fuels derived from a combination of coal (84 percent by weight) and switchgrass (16 percent by weight) feedstocks. Like other scenarios, Scenario 2 assesses a 1:1 blend F-T and conventional jet fuel (US Average) over a period of 30 years. Illinois No. 6 sub-bituminous coal feedstock is shipped via train to a CBTL facility located in Northern Missouri. Regionally-grown and harvested switchgrass is shipped by diesel truck to the same facility, where it is dried and processed. The F-T process employed at the facility uses an iron catalyst without autothermal reforming, and with 91 percent flue gas carbon capture. The F-T process produces a combination of F-T jet fuel (52.9 percent by energy), F-T diesel (37.3 percent by energy), and F-T naphtha (9.83 percent by energy). Captured carbon dioxide is conveyed via a 775 mile pipeline to the Permian Basin in Texas, where it is used as an injectant in support of CO_2 EOR, and eventually sequestered. The EOR process also results in the production of crude oil and natural gas liquids. Finally, the F-T jet fuel is conveyed via pipeline from the CBTL Facility to a separate blending facility, located at the Woods River Refinery in Illinois. Here it is blended with conventional jet fuel and shipped via pipeline to Chicago O'Hare Airport. Alternatively, the blended fuel may be shipped via a combination of pipeline and tanker truck to Chicago O'Hare and smaller regional airports. Scenario 2 is most closely related to Scenarios 3, 7, and 8, which also incorporate coal and biomass using an iron F-T catalyst. Table 139 provides an overview of key values for Scenario 2.

Table 139. Scenario 2 Overview

Item		Scenario Property		
Study Properties				
Functional Unit		1 MJ of Blended F-T Jet Fuel Consumed		
Blended F-T Jet Fuel		4,010 MJ/bbl		
F-T Jet Fuel		50 percent of final product (by volume)		
Conventional Jet Fuel (US Average)		50 percent of final product (by (volume)		
Temporal Boundary		30 years		
CBTL Facility Properties				
Plant Location		Northern Missouri		
Daily Production Capacity		30,000 bbl/d		
F-T Catalyst Type		Iron		
Autothermal Reforming		No		
Tail Gas Recycle		Yes		
Carbon Capture		91 percent in flue gas		
Optimized for Maximum F-T Jet Fuel Production		No		
Item	**Value**	**Units**	**Value**	**Units**
Energy Feedstock Inputs to CBTL Facility				
Coal, Illinois No. 6	11,353	short tons/day	84%	percent by mass
Biomass, Switchgrass	1,803	short tons/day	16%	percent by mass
Product Outputs from CBTL Plant				
CBTL Plant Liquid Product Output	30,000	bbl/d	100%	percent by energy
CBTL Plant F-T Jet Fuel Production	15,939	bbl/d	52.9%	percent by energy
CBTL Plant F-T-Diesel Fuel Production	10,769	bbl/d	37.3%	percent by energy
CBTL Plant F-T Naphtha Production	3,292	bbl/d	9.83%	percent by energy
Carbon Management Strategy: CO_2-Enhanced Oil Recovery (CO_2-EOR)				
Storage Location	Permian Basin, TX		775	miles from CBTL Facility
Carbon Dioxide Sequestered	15,778	short tons/day	99.5%	percent of CO_2 received
Crude Oil Production	63,440	bbl/d	97.3%	percent by energy
Natural Gas Liquids Production	2,928	bbl/d	2.7%	percent by energy
Carbon Management Strategy: Saline Aquifer				
Storage Location	N/A		N/A	N/A
Carbon Dioxide Sequestered	N/A	N/A	N/A	N/A
Product Transport to Airport				
F-T Jet Fuel Pipeline Transport to Wood River, Il Refinery	21,595	bbl/d	225	miles
Blended F-T Jet Fuel Pipeline Transport to Chicago O'Hare Airport	22,346	bbl/d	245	miles



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (dry)	52.9	g/MJ LHV	6	F-T Naphtha	2.04	g/MJ LHV	11	F-T Jet Fuel	11.0	g/MJ LHV
2	Switchgrass (dry)	9.44	g/MJ LHV	7	Supercritical CO_2	83.7	g/MJ LHV	12	F-T Jet Fuel	11.0	g/MJ LHV
3	Illinois No. 6 Coal (dry)	52.9	g/MJ LHV	8	Supercritical CO_2	83.1	g/MJ LHV	13	Conv. Jet Fuel	11.8	g/MJ LHV
4	Switchgrass (dry)	9.44	g/MJ LHV	9	Crude Oil	50.8	g/MJ LHV	14	Blended Jet Fuel	22.8	g/MJ LHV
5	F-T Diesel	7.75	g/MJ LHV	10	Natural Gas Liquids	1.29	g/MJ LHV	15	Blended Jet Fuel	22.8	g/MJ LHV

Figure 65. Scenario 2: System Boundary and Major Flows (g/MJ Jet Fuel Combusted, LHV)

10.2.2 Life Cycle GHG Results

Lifecycle GHG results are presented below for the deterministic analysis using the best estimate for each modeling parameter, probabilistic uncertainty analysis using the defined uncertainty ranges and probability distributions sampled approximately 2,000 times using a Monte Carlo simulation, and sensitivity analysis to determine the key modeling parameters within the life cycle with greatest influence on the results.

10.2.2.1 Deterministic Analysis Results

Allocated results are tabulated in terms of life cycle sub-categories in Table 140 for both energy allocation and system expansion/displacement allocation method. Total unallocated CO_2e emissions are also provided along with each allocated result to assist understanding of the effect of allocation on each final result. The unallocated results do not represent the life cycle GHG result for 1 MJ of blended F-T Jet Fuel consumed. Unallocated results represent the total GHG emissions released to the atmosphere to produce the suite of co-products produced within the study boundary.

The deterministic analysis results in a 6 percent reduction in life cycle GHG emissions in comparison to a conventional jet fuel baseline of 87.4 g CO_2e/MJ jet fuel combusted, LHV when allocated by energy. Allocation of the co-products using the displacement method results a 5 percent reduction in the life cycle GHG profile compared to conventional jet fuel baseline. Thus the deterministic results of this study show that the life cycle GHG profile for Scenario 2 is 6 percent to 5 percent below the conventional jet fuel baseline.

Table 140. Scenario 2 Deterministic Analysis Results (Using IPCC 2007 GWP)

Life Cycle Stage Sub-categories	Unallocated CO_2e Emissions[1]		CO_2e Emissions Allocated by Energy		CO_2e Emissions Allocated by Displacement	
	g/MJ	%	g/MJ	%	g/MJ	%
LC Stage 1a: Illinois No. 6 Coal Acquisition	4.6	4.4%	0.7	0.8%	2.8	3.4%
LC Stage 2a: Coal Transport	0.8	0.8%	0.1	0.1%	0.5	0.6%
LC Stage 1b: Switchgrass Biomass Production	-15.4	-14.6%	-2.3	-2.8%	-21.3	-25.7%
LC Stage 1c: Direct Land Use	-0.4	-0.4%	-0.1	-0.1%	-0.5	-0.6%
LC Stage 1c: Indirect Land Use	1.4	1.3%	0.2	0.2%	0.9	1.1%
LC Stage 2b: Switchgrass Transport	0.4	0.4%	0.1	0.1%	0.2	0.2%
LC Stage 3a: CBTL Facility	8.1	7.7%	1.2	1.5%	4.9	5.9%
LC Stage 3b: Supercritical CO_2 Transport	0.8	0.8%	0.1	0.1%	0.5	0.6%
LC Stage 3c: Enhanced Oil Recovery (EOR)	26.7	25.3%	4.1	5.0%	16.4	19.8%
LC Stage 3d: Supercritical CO_2 Sequestration	0	0.0%	0	0.0%	0	0.0%
LC Stage 4: F-T Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 4: Conventional Jet Fuel Life Cycle	6.9	6.5%	6.9	8.4%	6.9	8.3%
LC Stage 4: Blended Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 5: Jet Fuel Use	71.4	67.6%	71.4	86.4%	71.4	86.0%
Life Cycle Total:	105.6	100.0%	82.6	100.0%	83.0	100.0%

1. Unallocated results represent all co-products produced within the system boundary therefore do not represent the life cycle GHG results for 1 MJ of blended F-T jet fuel consumed. The unallocated results are presented only to illustrate the effect of allocation.

Results by life cycle stage contribution show that fuel combustion (use phase) accounts for the majority of life cycle GHG emissions for both energy allocation (86 percent of total life cycle emissions) and displacement (86 percent of total lifecycle emissions) respectively. Excluding the use phase, the upstream life cycle stage with the next highest life cycle GHG contribution differs by the method of co-product allocation. The next largest contributor for the allocation by energy method is the conventional jet fuel production life cycle followed by EOR operation. Allocation by displacement method reverses this, with EOR operation followed by conventional jet fuel production life cycle as the next most significant contributors. Interestingly, the CBTL facility contributes only 1.5 percent to 5.9 percent to the total life cycle GHG profile, depending on method of allocation.

10.2.2.2 Probabilistic Uncertainty Analysis Results

Table 141 presents summary statistics for the resulting CO_2e emissions for Scenario 2 along with the "best estimate," which is the deterministic result. CO_2e emissions are presented using energy allocation and displacement. The minimum value, 25th percentile, median (50th percentile), 75th percentile and maximum value are presented for each probabilistic result. Also presented in Table 141 are statistics for the "combined" result. The "combined" result was generated by combining the probabilistic results for the two primary probabilistic results (i.e., the result for energy allocation and displacement allocation).

The probability distributions were generated for emissions allocated by energy and displacement by executing the F-T Jet Fuel Spreadsheet Model 2,000 times with values randomly selected from the distribution for each uncertain variable, during each iteration of the model. The combined result was obtained by randomly choosing results from either energy or displacement allocation at each iteration, and using the resulting 2,000 values to create the probability distribution for the combined result. In Table 141, the best estimate for the combined result is the average of the best estimates for energy and displacement allocation.

Figure 66 presents the probabilistic results in a "box and whisker" plot, for Scenario 2. In these plots, the bottom line of the box is the 25th percentile, the middle line is the median and the top line of the box is the 75th percentile. The outlier bars (the "whiskers") show minimum and maximum. The "x" marker indicates the best estimate and the solid line is the CO_2e emissions for conventional jet fuel. For Scenario 2, the maximum value is below the jet fuel baseline for the two primary results and the combined result. As shown, energy and displacement allocation result in approximately the same median and best estimate CO_2e emissions values under Scenario 2. However, the spread of the distribution for displacement allocation is larger, reflecting greater uncertainty under that allocation method.

Table 141. Scenario 2 Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

Quantity	CO_2e Emissions Allocated by Energy (g CO_2e/MJ LHV)	CO_2e Emissions Allocated by Displacement (g CO_2e/MJ LHV)	Combined CO_2e Emissions (g CO_2e/MJ LHV)
Minimum	82.1	79.3	79.9
25th Percentile	82.6	82.3	82.5
Median	82.7	83.0	82.7
75th Percentile	82.8	83.8	83.1
Maximum	83.3	86.5	86.4
Best Estimate	82.6	82.9	82.8
Conventional Jet Fuel	87.4	87.4	87.4

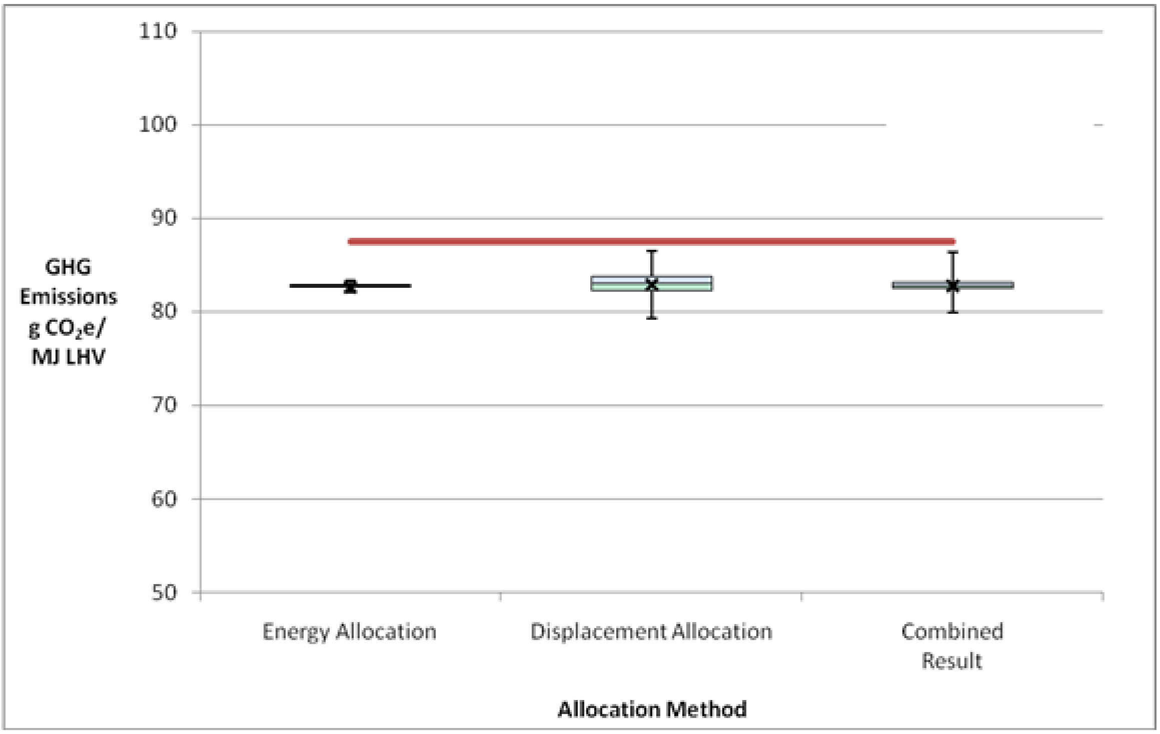


Figure 66. Scenario 2 Box and Whisker Plot of Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

10.2.2.3 Sensitivity Analysis Results

Sensitivity analysis results were calculated for both co-product allocation procedures (energy allocation and displacement method) by adjusting each modeling parameter independently between the minimum and maximum values to determine the effect on the final life cycle GHG result. The 24 modeling parameters with the greatest effect on the results was determined and ranked from highest to lowest based on their absolute difference. The results are reported in both tabular and graphical form in Table 142 and Figure 67 for the energy allocation results and Table 143 and Figure 68 for the displacement method results. All results are reported based on the IPCC 2007 global warming potentials.

Table 142. Scenario 2 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	87.4	86.4	0.992
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.7	87.3	86.5	0.805
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	86.5	87.3	0.718
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	86.6	87.2	0.563
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS_3d	tonne/tonne	0.005	0	0.01	86.7	87.1	0.444
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	86.8	87	0.236
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	86.8	87	0.217
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	86.8	87	0.184
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	86.9	87	0.117
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	87	86.8	0.114
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	86.8	87	0.106
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	86.9	86.9	0.0943
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	775	698	853	86.9	86.9	0.0894

Table 142. Scenario 2 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	86.9	87	0.0794
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	86.9	86.9	0.0346
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	86.9	86.9	0.0222
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	0	0	0	86.9	86.9	0
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air_3c	kg/kg	0.005	0	0.01	86.9	86.9	0
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	86.9	86.9	0
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	86.9	86.9	0
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	86.9	86.9	0
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	86.9	86.9	0
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	86.9	86.9	0
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	0	0	0	86.9	86.9	0

Table 143. Scenario 2 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	87.7	85.8	1.87
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.7	87.4	85.9	1.52
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	86.1	87.4	1.35
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS_3d	tonne/tonne	0.005	0	0.01	86.3	87.2	0.837
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	86.5	87	0.563
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	86.5	87	0.446
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	86.6	86.9	0.375
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	86.6	86.9	0.346
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	86.9	86.6	0.215
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	86.7	86.8	0.178
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	775	698	853	86.7	86.8	0.169
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	86.7	86.9	0.15
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	86.7	86.9	0.117

Table 143. Scenario 2 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) ***(Cont'd)***

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	86.7	86.8	0.106
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	86.7	86.8	0.0418
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	86.7	86.8	0.0346
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	0	0	0	86.8	86.8	0
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air_3c	kg/kg	0.005	0	0.01	86.8	86.8	0
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	86.8	86.8	0
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	86.8	86.8	0
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	86.8	86.8	0
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	86.8	86.8	0
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	86.8	86.8	0
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	0	0	0	86.8	86.8	0

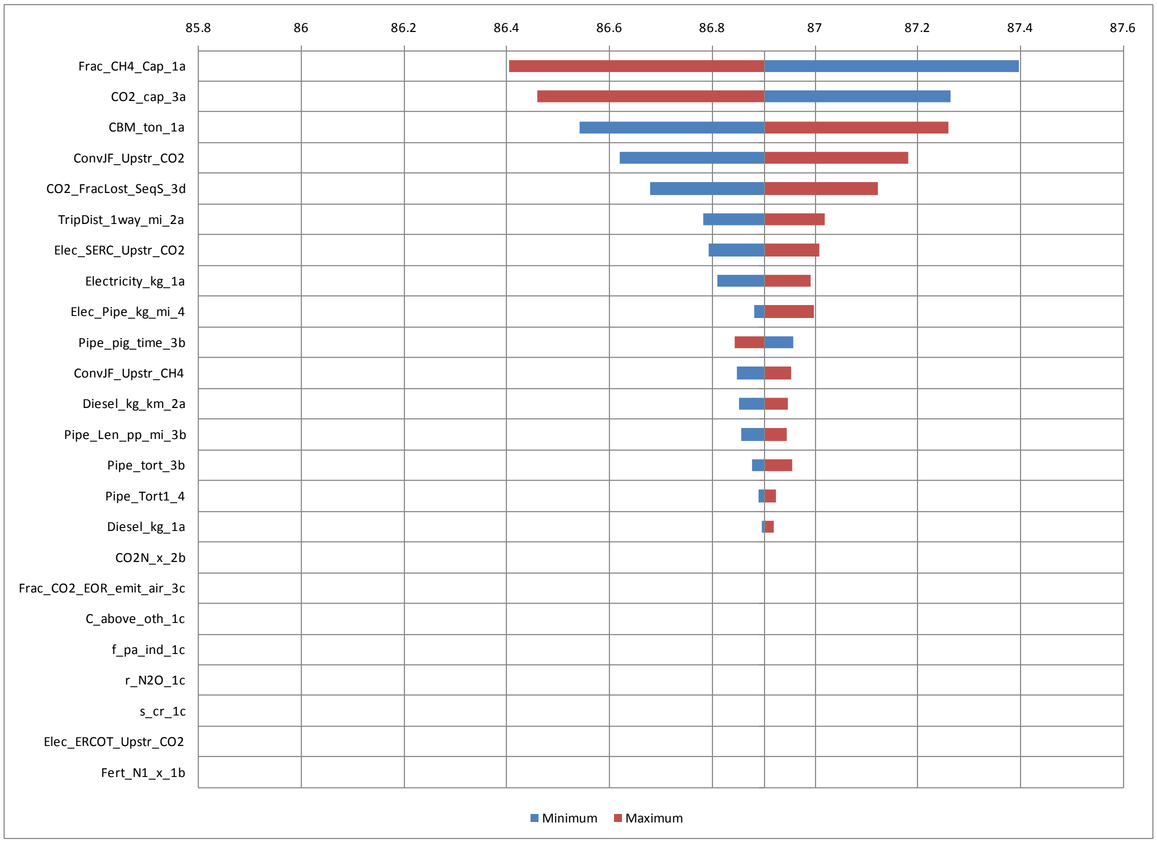


Figure 67. Scenario 2 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

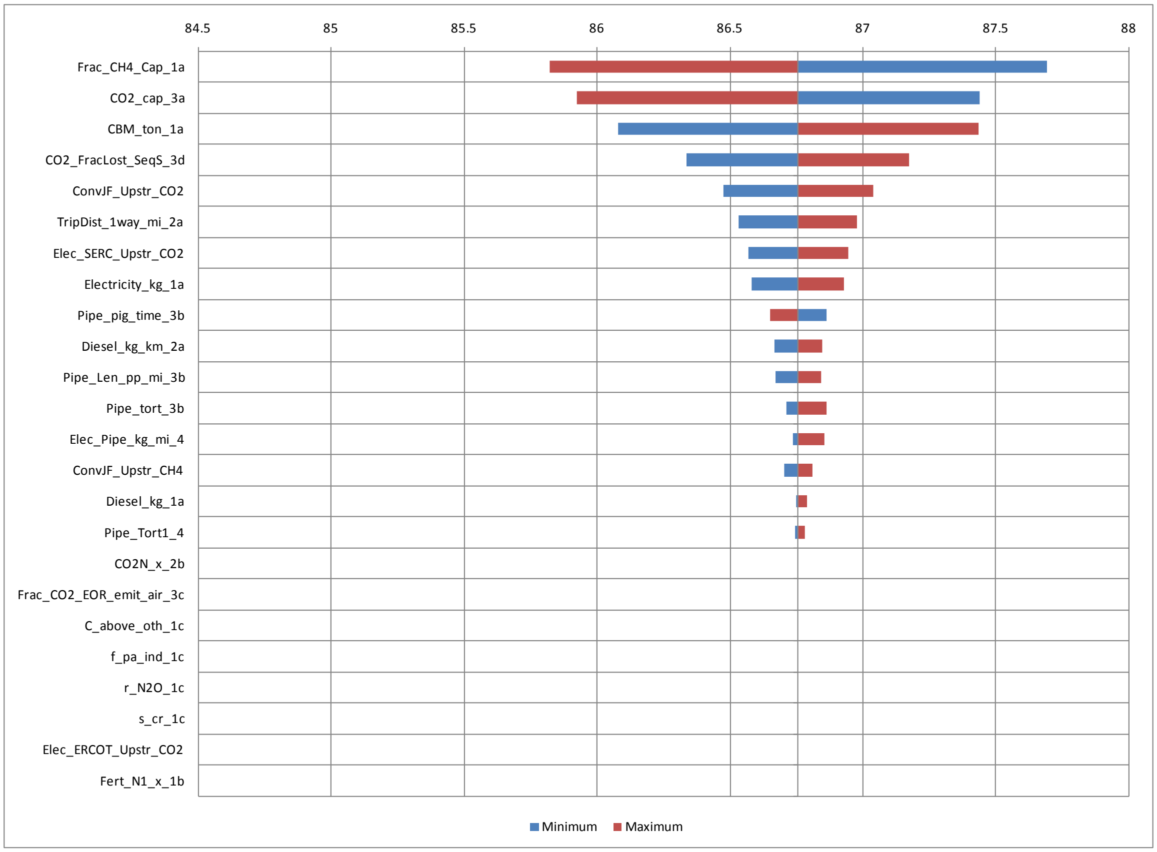


Figure 68. Scenario 2 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

10.2.3 Data Limitations

In terms of broader study limitations, the model boundaries and modeling choices contained in this scenario inform the following study limitations, which should be considered when interpreting final results and conclusions generated from this study:

- **Mine and Mine Methane Emissions:** this scenario presumes that Illinois No. 6 sub-bituminous coal from an underground longwall mine would be used, having an average methane emission rate of 150 scf CH_4/ton with 40 percent capture. Use of an alternative coal type, mine type, methane emission rate, or methane capture rate could increase or decrease mine and mine methane related GHG emissions.

- **Biomass Production:** this scenario presumes that farmed switchgrass would be used as the sole source of biomass. However, alternative sources of biomass could also have been chosen, such as farmed short rotation woody crops or corn stover, or biomass waste streams such as agricultural wastes or logging wastes. The use of alternative farming practices, crop requirements, and/or biomass source could increase or reduce life cycle GHG emissions.

- **Biomass Yields:** this scenario presumes that switchgrass production would yield 4.7 dry tons per acre per year of biomass. However, switchgrass yields reported in the literature

are highly variable, in part reflecting farming practices and regional conditions. Higher or lower switchgrass yield values could substantially decrease or increase life cycle land use, respectively.

- **Biomass Transport:** this scenario presumes a 50 mile switchgrass production radius. The intensity of biomass transport emissions is expected to increase with increases in production radius. Therefore, substantial increases in the biomass production radius for this study could result in concurrent increases in transportation related GHG emissions, as well as increases in cost, which under some cases could render a longer distance biomass collection scheme infeasible.
- **CBTL Facility Carbon Capture Rate:** the rate of carbon capture at the F-T facility used for this scenario is 91 percent, which is expected to be a conservative estimate of actual carbon capture rates. However, carbon capture facilities have not been widely implemented at the commercial scale. Therefore, a higher or lower carbon capture rate may apply to some future studies. Increases or decreases in this rate would result in concurrent increases or decreases in life cycle GHG emissions.
- **CBTL Facility Modeling Scenarios:** in order to model the F-T facility, output from a separate ASPEN model was incorporated into the life cycle model used for this study. As a result, the F-T facility model included in this study is static: the workings of the F-T facility cannot be updated or altered to evaluate different F-T facility parameters and setups, without performing substantial additional analysis. The F-T facility results from this study represent specific assumptions, as documented in **Section 6,** and are not necessarily representative of all potential F-T Facility designs.
- **EOR CO_2 Leakage Rates:** this scenario incorporates CO_2 leakage rates of less than one percent. However, actual leakage rates have not been extensively documented, and are expected to be difficult to monitor. Increases in CO_2 leakage rates could result in concurrent increases in life cycle GHG emissions.
- **Pre-Existence of Infrastructure:** some of the infrastructure needed within the boundary of this study, such as a pipeline network suitable for transferring F-T Jet Fuel to the blending facility, was assumed to be pre-existing. No GHG emissions penalty was included for this infrastructure.
- **Comparative Study Results:** the purpose of this study is to provide a comparative evaluation of alternative fuels against baseline 2005 conventional petroleum jet fuel production and use. Results provided for this scenario reflect life cycle emissions from alternative jet fuel production in comparison to that baseline. However, results from this scenario are not intended to provide absolute GHG emissions values; results from this study should be used with caution, when comparing to life cycle analyses having different baseline assumptions and study goals.

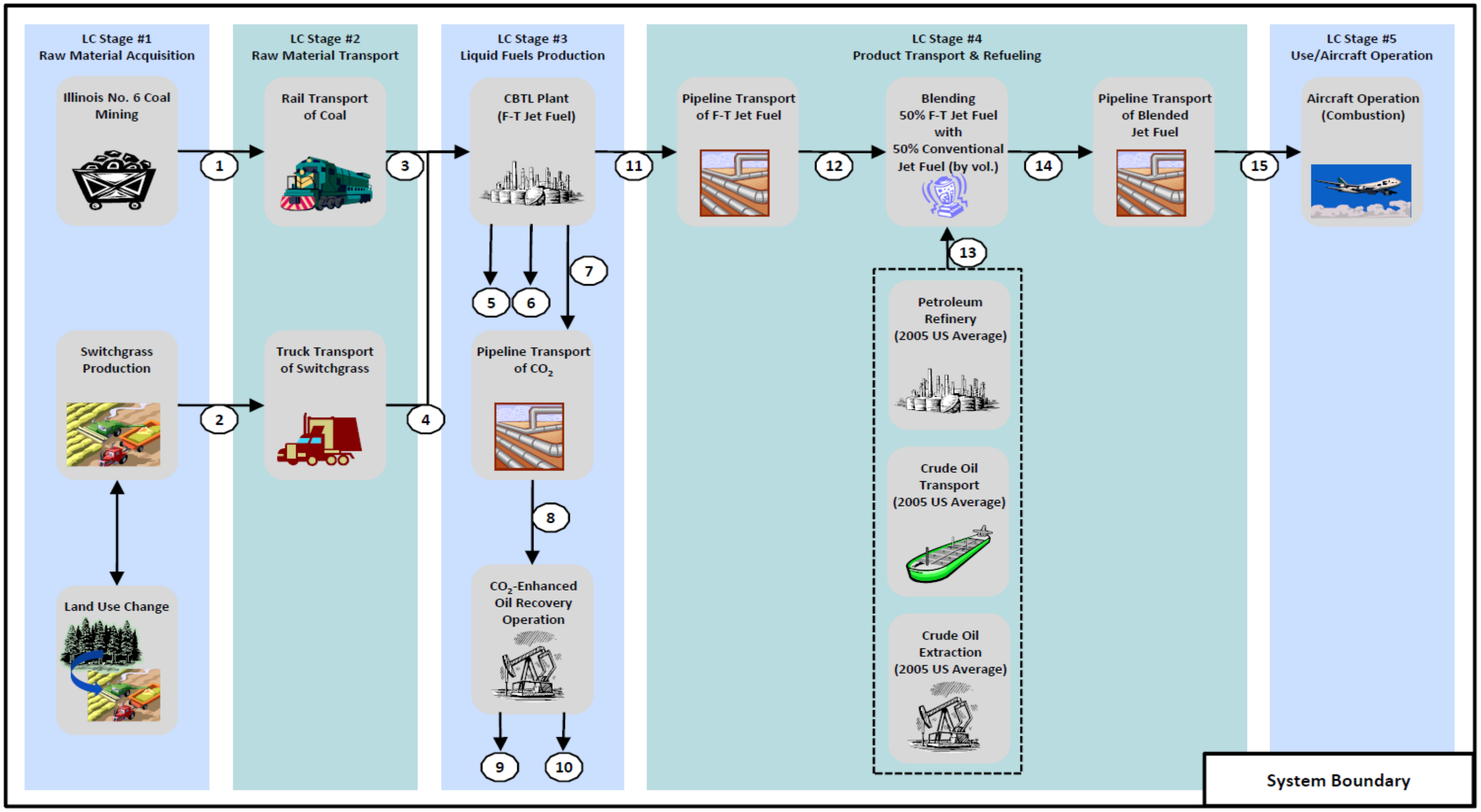
10.3 Scenario 3: 31 Percent Switchgrass, Iron F-T Catalyst, EOR

10.3.1 Scenario Overview

Scenario 3 was designed to evaluate F-T fuels derived from a combination of coal (69 percent by weight) and switchgrass (31 percent by weight) feedstocks. Like other scenarios, Scenario 3 assesses a 1:1 blend F-T and conventional jet fuel (US Average) over a period of 30 years. Illinois No. 6 sub-bituminous coal feedstock is shipped via train to a CBTL facility located in Northern Missouri. Regionally-grown and harvested switchgrass is shipped by diesel truck to the same facility, where it is dried and processed. The F-T process employed at the facility uses an iron catalyst without autothermal reforming, and with 91 percent flue gas carbon capture. The F-T process produces a combination of F-T jet fuel (52.9 percent by energy), F-T diesel (37.3 percent by energy), and F-T naphtha (9.83 percent by energy). Captured carbon dioxide is conveyed via a 775 mile pipeline to the Permian Basin in Texas, where it is used as an injectant in support of CO_2 EOR, and eventually sequestered. The EOR process also results in the production of crude oil and natural gas liquids. Finally, the F-T jet fuel is conveyed via pipeline from the CBTL Facility to a separate blending facility, located at the Woods River Refinery in Illinois. Here it is blended with conventional jet fuel and shipped via pipeline to Chicago O'Hare Airport. Alternatively, the blended fuel may be shipped via a combination of pipeline and tanker truck to Chicago O'Hare and smaller regional airports. Scenario 3 is an analogue to Scenario 2, except that Scenario 3 incorporates a higher proportion of switchgrass than Scenario 2. Scenario 3 is also closely related to Scenarios 7 and 8, which also incorporate coal and biomass using an iron F-T catalyst. Table 144 provides an overview of key values for Scenario 3.

Table 144. Scenario 3 Overview

Item	Scenario Property			
Study Properties				
Functional Unit	1 MJ of Blended F-T Jet Fuel Consumed			
Blended F-T Jet Fuel	4,010 MJ/bbl			
F-T Jet Fuel	50 percent of final product (by volume)			
Conventional Jet Fuel (US Average)	50 percent of final product (by (volume)			
Temporal Boundary	30 years			
CBTL Facility Properties				
Plant Location	Northern Missouri			
Daily Production Capacity	30,000 bbl/d			
F-T Catalyst Type	Iron			
Autothermal Reforming	No			
Tail Gas Recycle	Yes			
Carbon Capture	91 percent in flue gas			
Optimized for Maximum F-T Jet Fuel Production	No			
Item	**Value**	**Units**	**Value**	**Units**
Energy Feedstock Inputs to CBTL Facility				
Coal, Illinois No. 6	9,891	short tons/day	69%	percent by mass
Biomass, Switchgrass	3,816	short tons/day	31%	percent by mass
Product Outputs from CBTL Plant				
CBTL Plant Liquid Product Output	30,000	bbl/d	100%	percent by energy
CBTL Plant F-T Jet Fuel Production	15,939	bbl/d	52.9%	percent by energy
CBTL Plant F-T-Diesel Fuel Production	10,769	bbl/d	37.3%	percent by energy
CBTL Plant F-T Naphtha Production	3,292	bbl/d	9.83%	percent by energy
Carbon Management Strategy: CO_2-Enhanced Oil Recovery (CO_2-EOR)				
Storage Location	Permian Basin, TX		775	miles from CBTL Facility
Carbon Dioxide Sequestered	15,774	short tons/day	99.5%	percent of CO_2 received
Crude Oil Production	63,440	bbl/d	97.3%	percent by energy
Natural Gas Liquids Production	2,928	bbl/d	2.7%	percent by energy
Carbon Management Strategy: Saline Aquifer				
Storage Location	N/A		N/A	N/A
Carbon Dioxide Sequestered	N/A	N/A	N/A	N/A
Product Transport to Airport				
F-T Jet Fuel Pipeline Transport to Wood River, Il Refinery	21,595	bbl/d	225	miles
Blended F-T Jet Fuel Pipeline Transport to Chicago O'Hare Airport	22,346	bbl/d	245	miles



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (dry)	46.1	g/MJ LHV	6	F-T Naphtha	2.04	g/MJ LHV	11	F-T Jet Fuel	11.0	g/MJ LHV
2	Switchgrass (dry)	20.0	g/MJ LHV	7	Supercritical CO_2	83.7	g/MJ LHV	12	F-T Jet Fuel	11.0	g/MJ LHV
3	Illinois No. 6 Coal (dry)	46.1	g/MJ LHV	8	Supercritical CO_2	83.0	g/MJ LHV	13	Conv. Jet Fuel	11.8	g/MJ LHV
4	Switchgrass (dry)	20.0	g/MJ LHV	9	Crude Oil	50.8	g/MJ LHV	14	Blended Jet Fuel	22.8	g/MJ LHV
5	F-T Diesel	7.75	g/MJ LHV	10	Natural Gas Liquids	1.29	g/MJ LHV	15	Blended Jet Fuel	22.8	g/MJ LHV

Figure 69. Scenario 3: System Boundary and Major Flows (g/MJ Jet Fuel Combusted, LHV)

10.3.2 Life Cycle GHG Results

Lifecycle GHG results are presented below for the deterministic analysis using the best estimate for each modeling parameter, probabilistic uncertainty analysis using the defined uncertainty ranges, and probability distributions sampled approximately 2,000 times using a Monte Carlo simulation, and sensitivity analysis to determine the key modeling parameters within the life cycle with greatest influence on the results.

10.3.2.1 Deterministic Analysis Results

Allocated results are tabulated in terms of life cycle sub-categories in Table 145 for both energy allocation and system expansion/displacement allocation method. Total unallocated CO_2e emissions are also provided along with each allocated result to assist understanding of the effect of allocation on each final result. The unallocated results do not represent the life cycle GHG result for 1 MJ of blended F-T Jet Fuel consumed. Unallocated results represent the total GHG emissions released to the atmosphere to produce the suite of co-products produced within the study boundary.

Table 145. Scenario 3 Deterministic Analysis Results (Using IPCC 2007 GWP)

Life Cycle Stage Sub-categories	Unallocated CO_2e Emissions[1]		CO_2e Emissions Allocated by Energy		CO_2e Emissions Allocated by Displacement	
	g/MJ	%	g/MJ	%	g/MJ	%
LC Stage 1a: Illinois No. 6 Coal Acquisition	4	4.4%	0.6	0.7%	2.9	4.3%
LC Stage 2a: Coal Transport	0.7	0.8%	0.1	0.1%	0.5	0.7%
LC Stage 1b: Switchgrass Biomass Production	-32.6	-36.2%	-5	-6.2%	-42.1	-62.6%
LC Stage 1c: Direct Land Use	-0.7	-0.8%	-0.1	-0.1%	-1	-1.5%
LC Stage 1c: Indirect Land Use	3	3.3%	0.5	0.6%	2.1	3.1%
LC Stage 2b: Switchgrass Transport	0.8	0.9%	0.1	0.1%	0.5	0.7%
LC Stage 3a: CBTL Facility	8.7	9.7%	1.3	1.6%	6.2	9.2%
LC Stage 3b: Supercritical CO_2 Transport	0.8	0.9%	0.1	0.1%	0.6	0.9%
LC Stage 3c: Enhanced Oil Recovery (EOR)	26.7	29.7%	4.1	5.1%	18.9	28.1%
LC Stage 3d: Supercritical CO_2 Sequestration	0	0.0%	0	0.0%	0	0.0%
LC Stage 4: F-T Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 4: Conventional Jet Fuel Life Cycle	6.9	7.7%	6.9	8.6%	6.9	10.3%
LC Stage 4: Blended Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 5: Jet Fuel Use	71.4	79.3%	71.4	88.9%	71.4	106.3%
Life Cycle Total:	90	100.0%	80.3	100.0%	67.2	100.0%

1. Unallocated results represent all co-products produced within the system boundary, therefore do not represent the life cycle GHG results for 1 MJ of blended F-T jet fuel consumed. The unallocated results are presented only to illustrate the effect of allocation.

The deterministic analysis results in an 8 percent reduction in life cycle GHG emissions in comparison to a conventional jet fuel baseline of 87.4 g CO_2e/MJ jet fuel combusted, LHV when allocated by energy. Allocation of the co-products using the displacement method results a 23 percent reduction in the life cycle GHG profile compared to conventional jet fuel baseline. Thus the deterministic results of this study show that the life cycle GHG profile for Scenario 3 is 23 percent to 8 percent below the conventional jet fuel baseline.

Results by life cycle stage contribution show that fuel combustion (use phase) accounts for the majority of life cycle GHG emissions for both energy allocation (89 percent of total life cycle

emissions) and displacement (106 percent of total lifecycle emissions) respectively. Note that biogenic carbon uptake by switchgrass is denoted using negative emission values; therefore emissions of over 100 percent of total life cycle emissions are possible for fuel combustion alone. Excluding the use phase, the upstream life cycle stage with the next highest life cycle GHG emissions contribution differs by the method of co-product allocation. The next largest emissions contributor for the allocation by energy method is the conventional jet fuel production life cycle followed by EOR operation. Allocation by displacement method reverses this, with EOR operation followed by conventional jet fuel production life cycle as the next most significant contributors. Interestingly, the CBTL facility contributes only 1.6 percent to 9.2 percent to the total life cycle GHG profile, depending on method of allocation. Also, the importance of carbon uptake by switchgrass ranges from -6.2 percent to -62 percent of total life cycle emissions.

10.3.2.2 Probabilistic Uncertainty Analysis Results

Table 146 presents summary statistics for probabilistic CO_2e emissions for Scenario 3 (31 percent switchgrass, iron catalyst, normal production of F-T jet fuel and EOR) along with the "best estimate" (i.e., the deterministic result). Figure 70 presents the probabilistic results in a "box and whisker" plot. Table 146 has the same structure as Table 141, while Figure 70 has the same structure as Figure 66**.**

For Scenario 3, all results, including energy allocation and displacement allocation, are below the conventional jet fuel emissions level. As shown, median CO_2e emissions using energy allocation are 7.1 g CO_2e/MJ LHV below conventional jet fuel emissions. Results using displacement allocation show substantially reduced lifecycle CO_2e emissions for Scenario 3, with a median value that is 20.2 g CO_2e/MJ LHV below conventional jet fuel emissions. In addition, the entire distributions for energy and displacement allocation are at least 6.3 g CO_2e/MJ LHV below conventional jet fuel emissions. Comparing Scenarios 1-3 indicates that as the percentage of switchgrass included in the CBTL facility feedstock increases, total lifecycle CO_2e emissions decline substantially.

Table 146. Scenario 3 Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

Quantity	CO_2e Emissions Allocated by Energy (g CO_2e/MJ LHV)	CO_2e Emissions Allocated by Displacement (g CO_2e/MJ LHV)	Combined CO_2e Emissions (g CO_2e/MJ LHV)
Minimum	79.6	62.0	63.2
25th Percentile	80.2	66.2	67.3
Median	80.3	67.2	71.1
75th Percentile	80.5	68.3	80.3
Maximum	81.1	71.6	81.1
Best Estimate	80.3	67.1	73.7
Conventional Jet Fuel	87.4	87.4	87.4

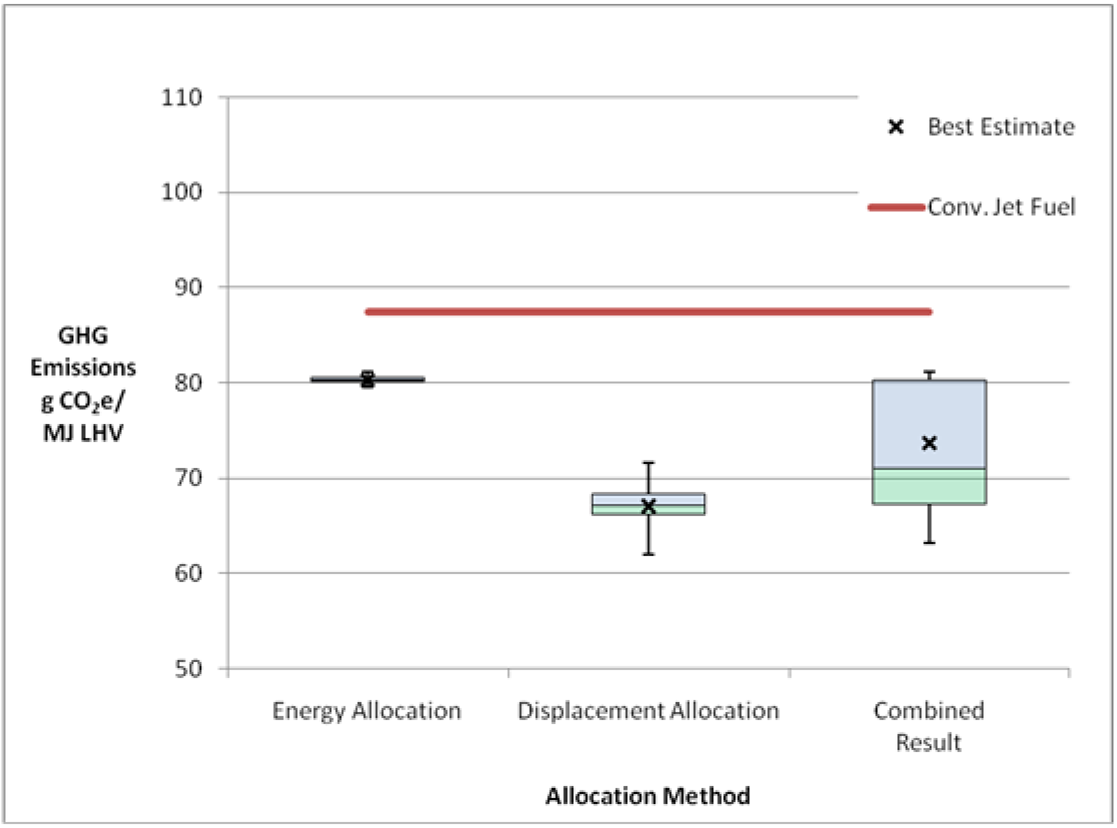


Figure 70. Scenario 3 Box and Whisker Plot of Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

10.3.2.3 Sensitivity Analysis Results

Sensitivity analysis results were calculated for both co-product allocation procedures (energy allocation and displacement method) by adjusting each modeling parameter independently between the minimum and maximum values to determine the effect on the final life cycle GHG result. The 24 modeling parameters with the greatest effect on the results was determined and ranked from highest to lowest based on their absolute difference. The results are reported in both tabular and graphical form in Table 147 and Figure 71 for the energy allocation results and Table 148 and Figure 72 for the displacement method results. All results are reported based on the IPCC 2007 global warming potentials.

Table 147. Scenario 3 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	82.4	82.9	0.563
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	82.8	82.5	0.254
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	82.6	82.8	0.239
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.7	82.7	82.5	0.231
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	82.6	82.7	0.184
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	82.6	82.7	0.171
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air_3c	kg/kg	0.005	0	0.01	82.6	82.7	0.126
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	82.7	82.6	0.123
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	82.6	82.7	0.117
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	82.6	82.7	0.106
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	82.6	82.7	0.106
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	82.6	82.7	0.102
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	82.6	82.7	0.087
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	82.6	82.7	0.0605
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	82.6	82.7	0.047
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	82.6	82.7	0.0346

Table 147. Scenario 3 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	82.7	82.6	0.0325
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	775	698	853	82.6	82.7	0.0255
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	82.6	82.7	0.0241
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	82.6	82.7	0.0227
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	82.6	82.6	0.011
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	82.6	82.6	0.00567
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	82.6	82.6	0.00531
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	82.6	82.6	0.00492

Table 148. Scenario 3 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	81.9	84.2	2.28
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	83.8	82.1	1.68
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.7	83.6	82.1	1.53
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	83.5	81.9	1.52
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	82.3	83.5	1.21
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	82.4	83.5	1.13
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air_3c	kg/kg	0.005	0	0.01	82.5	83.3	0.835
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	82.6	83.3	0.703
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	82.6	83.3	0.677
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	82.6	83.2	0.563
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	82.7	83.1	0.4
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	82.7	83.1	0.356
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	82.8	83.1	0.311
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	83	82.8	0.215
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	775	698	853	82.8	83	0.169
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	82.8	83	0.159

Table 148. Scenario 3 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) *(Cont'd)*

Variable Name	Variable Symbol Units		Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimates	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	82.9	83	0.15
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	82.9	83	0.117
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	82.9	83	0.106
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	82.9	83	0.0719
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	82.9	83	0.0375
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	82.9	82.9	0.0348
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	82.9	82.9	0.0346
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	82.9	82.9	0.0325

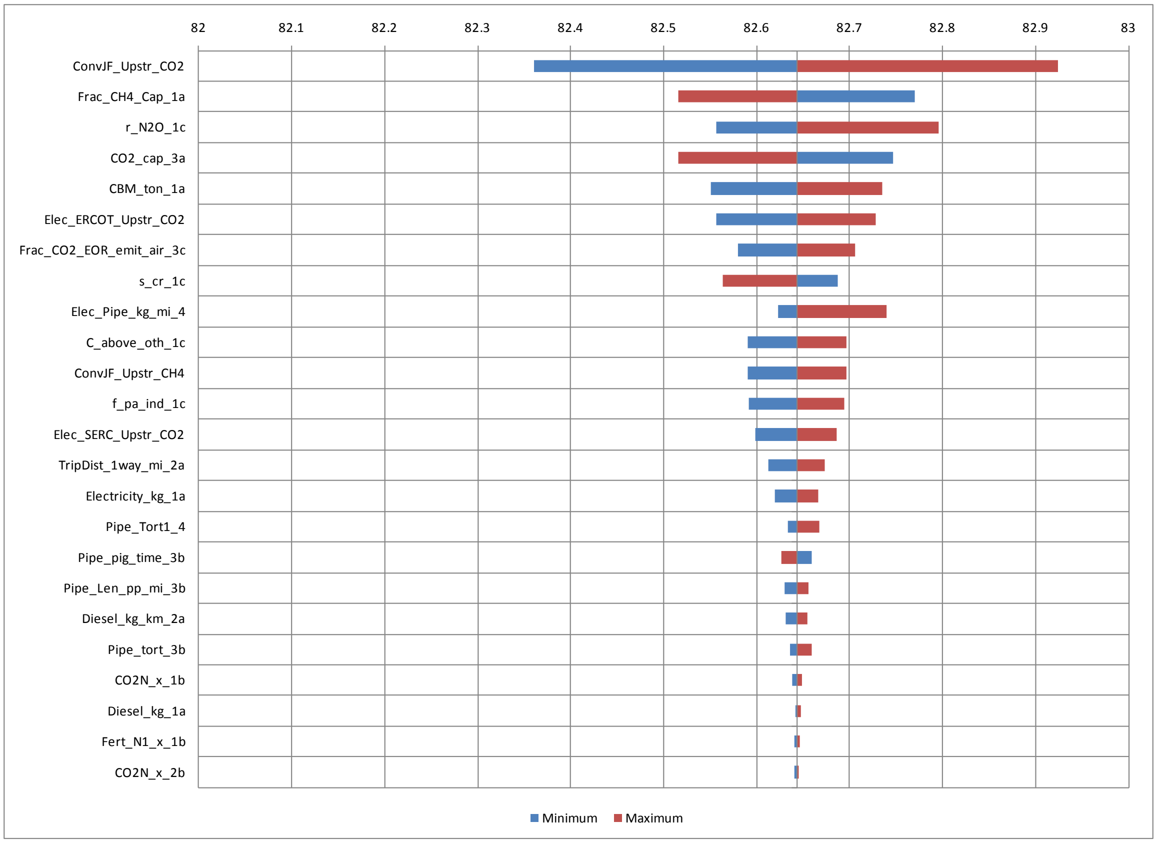


Figure 71. Scenario 3 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

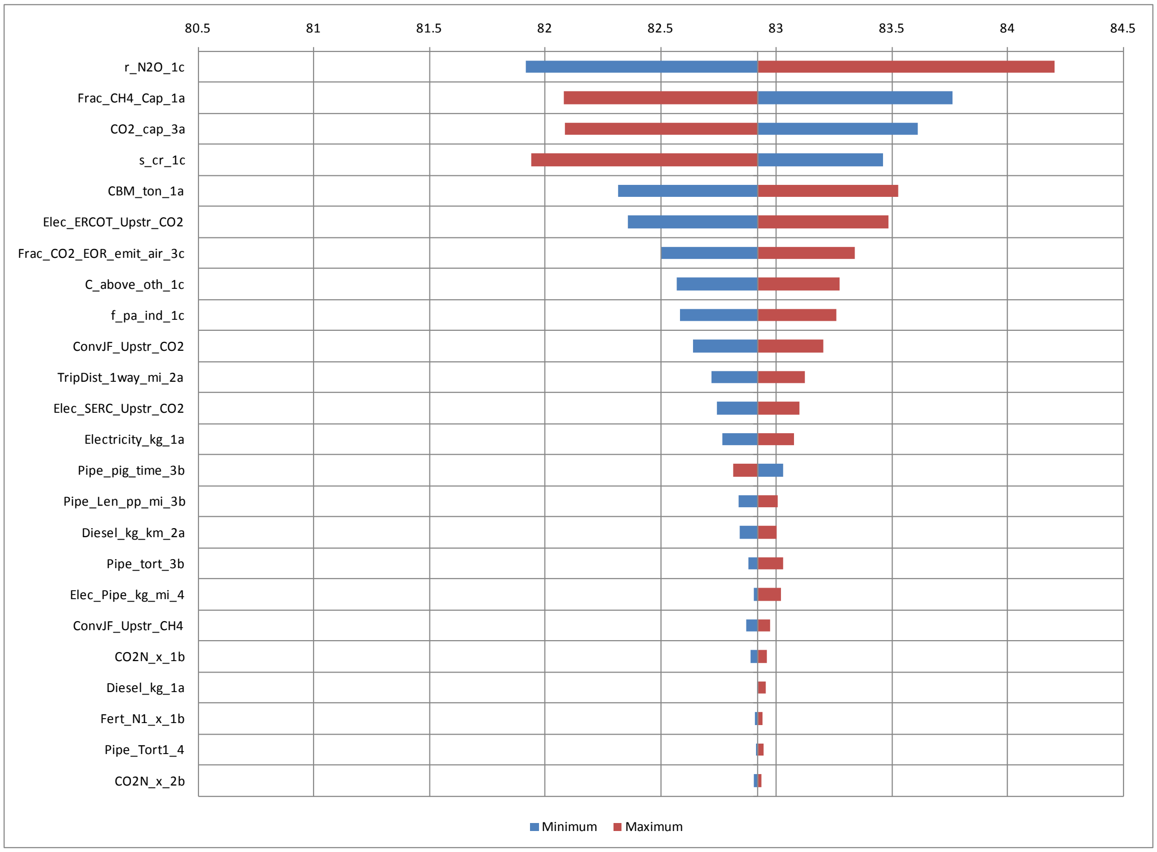


Figure 72. Scenario 3 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

10.3.3 Data Limitations

In terms of broader study limitations, the model boundaries and modeling choices contained in this scenario inform the following study limitations, which should be considered when interpreting final results and conclusions generated from this study:

- **Mine and Mine Methane Emissions:** this scenario presumes that Illinois No. 6 sub-bituminous coal from an underground longwall mine would be used, having an average methane emission rate of 150 scf CH_4/ton with 40 percent capture. Use of an alternative coal type, mine type, methane emission rate, or methane capture rate could increase or decrease mine and mine methane related GHG emissions.
- **Biomass Production:** This scenario presumes that farmed switchgrass would be used as the sole source of biomass. However, alternative sources of biomass could also have been chosen, such as farmed short rotation woody crops or corn stover, or biomass waste streams such as agricultural wastes or logging wastes. The use of alternative farming practices, crop requirements, and/or biomass source could increase or reduce life cycle GHG emissions.
- **Biomass Yields:** This scenario presumes that switchgrass production would yield 4.7 dry tons per acre per year of biomass. However, switchgrass yields reported in the literature

are highly variable, in part reflecting farming practices and regional conditions. Higher or lower switchgrass yield values could substantially decrease or increase life cycle land use, respectively.

- **Biomass Transport:** This scenario presumes a 50-mile switchgrass production radius. The intensity of biomass transport emissions is expected to increase with increases in production radius. Therefore, substantial increases in the biomass production radius for this study could result in concurrent increases in transportation related GHG emissions, as well as increases in cost, which under some cases could render a longer distance biomass collection scheme infeasible.

- **CBTL Facility Carbon Capture Rate:** The rate of carbon capture at the F-T facility used for this scenario is 91 percent, which is expected to be a conservative estimate of actual carbon capture rates. However, carbon capture facilities have not been widely implemented at the commercial scale. Therefore, a higher or lower carbon capture rate may apply to some future studies. Increases or decreases in this rate would result in concurrent increases or decreases in life cycle GHG emissions.

- **CBTL Facility Modeling Scenarios:** In order to model the F-T facility, output from a separate ASPEN model was incorporated into the life cycle model used for this study. As a result, the F-T facility model included in this study is static: the workings of the F-T facility cannot be updated or altered to evaluate different F-T facility parameters and setups, without performing substantial additional analysis. The F-T facility results from this study represent specific assumptions, as documented in **Section 6**, and are not necessarily representative of all potential F-T Facility designs.

- **EOR CO_2 Leakage Rates:** This scenario incorporates CO_2 leakage rates of less than one percent. However, actual leakage rates have not been extensively documented, and are expected to be difficult to monitor. Increases in CO_2 leakage rates could result in concurrent increases in life cycle GHG emissions.

- **Pre-Existence of Infrastructure:** Some of the infrastructure needed within the boundary of this study, such as a pipeline network suitable for transferring F-T Jet Fuel to the blending facility, was assumed to be pre-existing. No GHG emissions penalty was included for this infrastructure.

- **Comparative Study Results:** The purpose of this study is to provide a comparative evaluation of alternative fuels against baseline 2005 conventional petroleum jet fuel production and use. Results provided for this scenario reflect life cycle emissions from alternative jet fuel production in comparison to that baseline. However, results from this scenario are not intended to provide absolute GHG emissions values; results from this study should be used with caution, when comparing with life cycle analyses having different baseline assumptions and study goals.

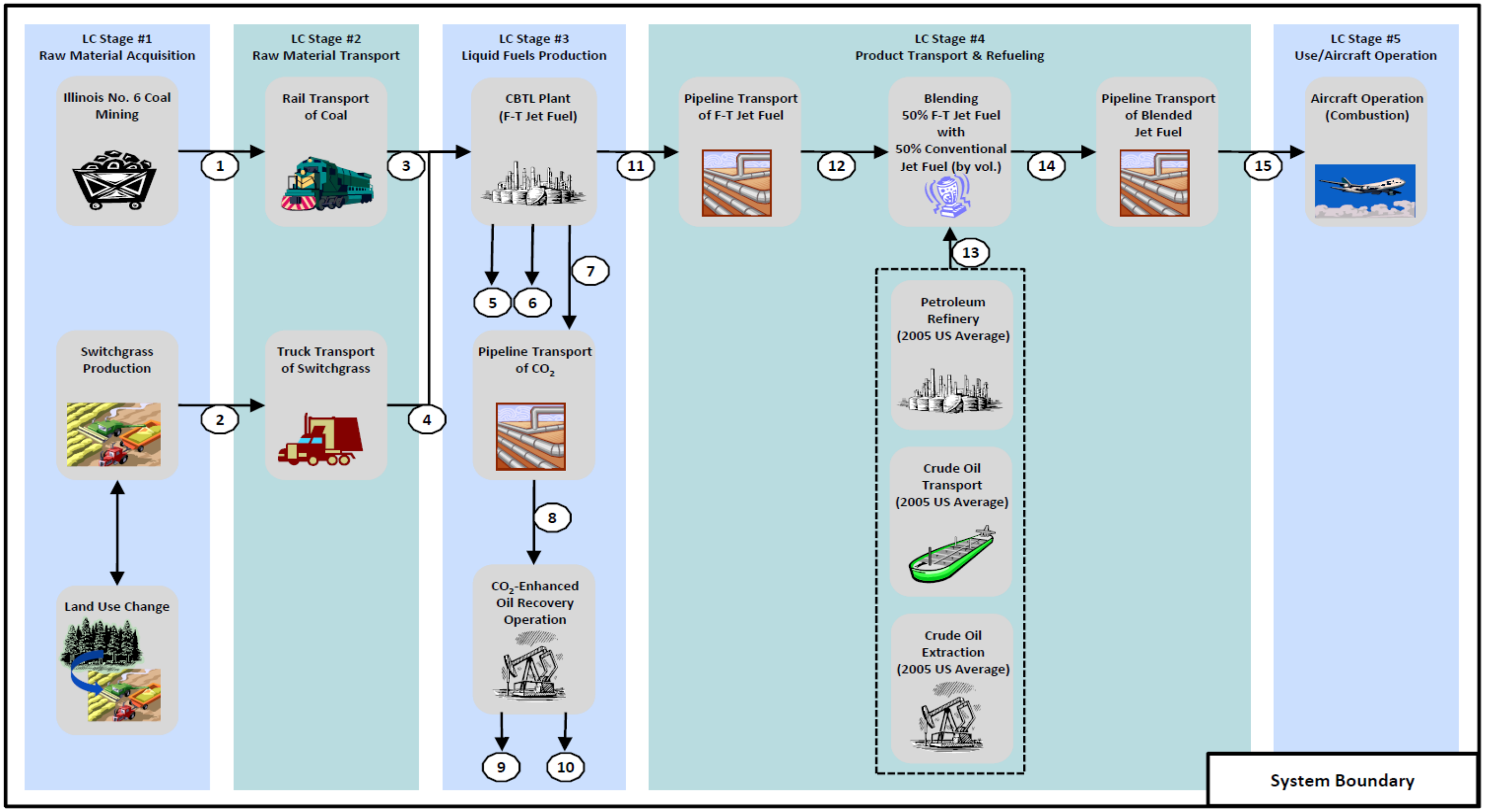
10.4 Scenario 4: 14 Percent Switchgrass, Cobalt F-T Catalyst, EOR

10.4.1 Scenario Overview

Scenario 4 was designed to evaluate F-T fuels derived from a combination of coal (86 percent by weight) and switchgrass (14 percent by weight) feedstocks. Like other scenarios, Scenario 4 assesses a 1:1 blend F-T and conventional jet fuel (US Average) over a period of 30 years. Illinois No. 6 sub-bituminous coal feedstock is shipped via train to a CBTL facility located in Northern Missouri. Regionally-grown and harvested switchgrass is shipped by diesel truck to the same facility, where it is dried and processed. Unlike Scenarios 1-3 and 6-8, the F-T process employed at the CBTL facility uses a cobalt catalyst with autothermal reforming, and with 91 percent flue gas carbon capture. The F-T process produces a combination of F-T jet fuel (58.1 percent by energy), F-T diesel (28.9 percent by energy), and F-T naphtha (13.1 percent by energy). Captured carbon dioxide is conveyed via a 775 mile pipeline to the Permian Basin in Texas, where it is used as an injectant in support of CO_2 EOR, and eventually sequestered. The EOR process also results in the production of crude oil and natural gas liquids. Finally, the F-T jet fuel is conveyed via pipeline from the CBTL Facility to a separate blending facility, located at the Woods River Refinery in Illinois. Here it is blended with conventional jet fuel and shipped via pipeline to Chicago O'Hare Airport. Alternatively, the blended fuel may be shipped via a combination of pipeline and tanker truck to Chicago O'Hare and smaller regional airports. Scenario 4 is most closely related to Scenario 9, which also incorporates coal and biomass using cobalt F-T catalyst. Table 149 provides an overview of key values for Scenario 4.

Table 149. Scenario 4 Overview

Item		Scenario Property		
Study Properties				
Functional Unit		1 MJ of Blended F-T Jet Fuel Consumed		
Blended F-T Jet Fuel		4,010 MJ/bbl		
F-T Jet Fuel		50 percent of final product (by volume)		
Conventional Jet Fuel (US Average)		50 percent of final product (by (volume)		
Temporal Boundary		30 years		
CBTL Facility Properties				
Plant Location		Northern Missouri		
Daily Production Capacity		30,000 bbl/d		
F-T Catalyst Type		Cobalt		
Autothermal Reforming		Yes		
Tail Gas Recycle		Yes		
Carbon Capture		91 percent in flue gas		
Optimized for Maximum F-T Jet Fuel Production		No		
Item	**Value**	**Units**	**Value**	**Units**
Energy Feedstock Inputs to CBTL Facility				
Coal, Illinois No. 6	11,889	short tons/day	86%	percent by mass
Biomass, Switchgrass	1,602	short tons/day	14%	percent by mass
Product Outputs from CBTL Plant				
CBTL Plant Liquid Product Output	30,000	bbl/d	100%	percent by energy
CBTL Plant F-T Jet Fuel Production	17,363	bbl/d	58.1%	percent by energy
CBTL Plant F-T-Diesel Fuel Production	8,302	bbl/d	28.9%	percent by energy
CBTL Plant F-T Naphtha Production	4,335	bbl/d	13.1%	percent by energy
Carbon Management Strategy: CO_2-Enhanced Oil Recovery (CO_2-EOR)				
Storage Location	Permian Basin, TX		775	miles from CBTL Facility
Carbon Dioxide Sequestered	15,991	short tons/day	99.5%	percent of CO_2 received
Crude Oil Production	63,440	bbl/d	97.3%	percent by energy
Natural Gas Liquids Production	2,928	bbl/d	2.7%	percent by energy
Carbon Management Strategy: Saline Aquifer				
Storage Location	N/A		N/A	N/A
Carbon Dioxide Sequestered	N/A	N/A	N/A	N/A
Product Transport to Airport				
F-T Jet Fuel Pipeline Transport to Wood River, Il Refinery	23,618	bbl/d	225	miles
Blended F-T Jet Fuel Pipeline Transport to Chicago O'Hare Airport	24,341	bbl/d	245	miles



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (dry)	50.7	g/MJ LHV	6	F-T Naphtha	2.48	g/MJ LHV	11	F-T Jet Fuel	11.0	g/MJ LHV
2	Switchgrass (dry)	7.69	g/MJ LHV	7	Supercritical CO_2	77.7	g/MJ LHV	12	F-T Jet Fuel	11.0	g/MJ LHV
3	Illinois No. 6 Coal (dry)	50.7	g/MJ LHV	8	Supercritical CO_2	77.1	g/MJ LHV	13	Conv. Jet Fuel	11.8	g/MJ LHV
4	Switchgrass (dry)	7.69	g/MJ LHV	9	Crude Oil	46.6	g/MJ LHV	14	Blended Jet Fuel	22.8	g/MJ LHV
5	F-T Diesel	5.47	g/MJ LHV	10	Natural Gas Liquids	1.18	g/MJ LHV	15	Blended Jet Fuel	22.8	g/MJ LHV

Figure 73. Scenario 4: System Boundary and Major Flows (g/MJ Jet Fuel Combusted, LHV)

10.4.2 Life Cycle GHG Results

Lifecycle GHG results are presented below for the deterministic analysis using the best estimate for each modeling parameter, probabilistic uncertainty analysis using the defined uncertainty ranges and probability distributions sampled approximately 2,000 times using a Monte Carlo simulation, and sensitivity analysis to determine the key modeling parameters within the life cycle with greatest influence on the results.

10.4.2.1 Deterministic Analysis Results

Allocated results are tabulated in terms of life cycle sub-categories in Table 150 for both energy allocation and system expansion/displacement allocation method. Total unallocated CO_2e emissions are also provided along with each allocated result to assist understanding of the effect of allocation on each final result. The unallocated results do not represent the life cycle GHG result for 1 MJ of blended F-T Jet Fuel consumed. Unallocated results represent the total GHG emissions released to the atmosphere to produce the suite of co-products produced within the study boundary.

Table 150. Scenario 4 Deterministic Analysis Results (Using IPCC 2007 GWP)

Life Cycle Stage Sub-categories	Unallocated CO_2e Emissions[1]		CO_2e Emissions Allocated by Energy		CO_2e Emissions Allocated by Displacement	
	g/MJ	%	g/MJ	%	g/MJ	%
LC Stage 1a: Illinois No. 6 Coal Acquisition	4.5	4.2%	0.7	0.8%	2.8	3.3%
LC Stage 2a: Coal Transport	0.8	0.8%	0.1	0.1%	0.5	0.6%
LC Stage 1b: Switchgrass Biomass Production	-12.5	-11.8%	-2.1	-2.5%	-17.2	-20.0%
LC Stage 1c: Direct Land Use	-0.3	-0.3%	0	0.0%	-0.4	-0.5%
LC Stage 1c: Indirect Land Use	1.2	1.1%	0.2	0.2%	0.7	0.8%
LC Stage 2b: Switchgrass Transport	0.3	0.3%	0	0.0%	0.2	0.2%
LC Stage 3a: CBTL Facility	8.3	7.8%	1.4	1.7%	5.2	6.0%
LC Stage 3b: Supercritical CO_2 Transport	0.8	0.8%	0.1	0.1%	0.5	0.6%
LC Stage 3c: Enhanced Oil Recovery (EOR)	24.5	23.1%	4.1	4.9%	15.4	17.9%
LC Stage 3d: Supercritical CO_2 Sequestration	0	0.0%	0	0.0%	0	0.0%
LC Stage 4: F-T Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 4: Conventional Jet Fuel Life Cycle	6.9	6.5%	6.9	8.3%	6.9	8.0%
LC Stage 4: Blended Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 5: Jet Fuel Use	71.3	67.3%	71.3	85.9%	71.3	82.8%
Life Cycle Total:	105.9	100.0%	83	100.0%	86.1	100.0%

1. Unallocated results represent all co-products produced within the system boundary therefore do not represent the life cycle GHG results for 1 MJ of blended F-T jet fuel consumed. The unallocated results are presented only to illustrate the effect of allocation.

The deterministic analysis results in a 5 percent reduction in life cycle GHG emissions in comparison to a conventional jet fuel baseline of 87.4 g CO_2e/MJ jet fuel combusted, LHV when allocated by energy. Allocation of the co-products using the displacement method results a 1 percent reduction in the life cycle GHG profile compared to conventional jet fuel baseline. Thus the deterministic results of this study show that the life cycle GHG profile for Scenario 4 is 5 percent to 1 percent below the conventional jet fuel baseline.

Results by life cycle stage contribution show that fuel combustion (use phase) accounts for the majority of life cycle GHG emissions for both energy allocation (86 percent of total life cycle

emissions) and displacement (83 percent of total lifecycle emissions) respectively. Excluding the use phase, the upstream life cycle stage with the next highest life cycle GHG emissions contribution differs by the method of co-product allocation. The next largest emissions contributor for the allocation by energy method is the conventional jet fuel production life cycle followed by EOR operation. Allocation by displacement method reverses this, with EOR operation followed by conventional jet fuel production life cycle as the next most significant contributors. Interestingly, the CBTL facility contributes only 1.7 percent to 6.0 percent to the total life cycle GHG profile, depending on method of allocation.

10.4.2.2 Probabilistic Uncertainty Analysis Results

Table 151 presents summary statistics for probabilistic CO_2e emissions for Scenario 4 (14 percent switchgrass, cobalt F-T catalyst, normal product slate, and EOR) along with the "best estimate" (i.e., the deterministic result). Figure 74 presents the probabilistic results in a "box and whisker" plot. Table 151 has the same structure as Table 141 and Figure 74 has the same structure as Figure 66**.**

Scenario 4, which includes the use of a cobalt catalyst with 14 percent switchgrass incorporated into the CBTL facility feedstock, results in median CO_2e emissions that are below conventional jet fuel emissions for both energy (4.4 g CO_2e/MJ LHV below) and displacement (1.2 g CO_2e/MJ LHV below) allocation. However, the upper tail of the distribution for displacement allocation exceeds conventional jet fuel lifecycle emissions by 1.7 g CO_2e/MJ LHV. Note that for Scenario 2, which is analogous to Scenario 4 except with an iron catalyst, all probabilistic values were shown to be below jet fuels emissions. This result is due at least in part to a slightly lower percentage of switchgrass feed used under Scenario 4 (14 percent) as compared to Scenario 2 (16 percent).

Table 151. Scenario 4 Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

Quantity	CO_2e Emissions Allocated by Energy (g CO_2e/MJ LHV)	CO_2e Emissions Allocated by Displacement (g CO_2e/MJ LHV)	Combined CO_2e Emissions (g CO_2e/MJ LHV)
Minimum	82.5	83.0	82.5
25th Percentile	82.9	85.5	83.1
Median	83.0	86.2	84.5
75th Percentile	83.2	86.8	86.2
Maximum	83.6	89.1	89.0
Best Estimate	83.0	86.1	84.55
Conventional Jet Fuel	87.4	87.4	87.4

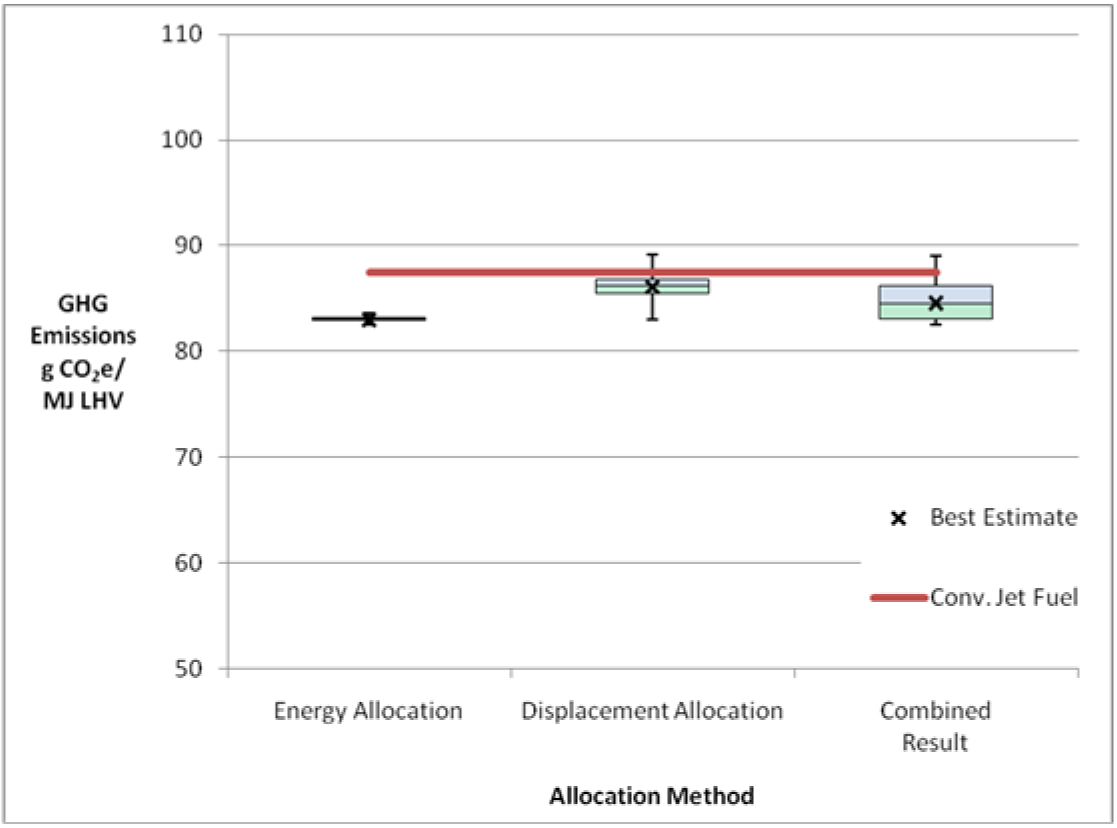


Figure 74. Scenario 4 Box and Whisker Plot of Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

10.4.2.3 Sensitivity Analysis Results

Sensitivity analysis results were calculated for both co-product allocation procedures (energy allocation and displacement method) by adjusting each modeling parameter independently between the minimum and maximum values to determine the effect on the final life cycle GHG result. The 24 modeling parameters with the greatest effect on the results was determined and ranked from highest to lowest based on their absolute difference. The results are reported in both tabular and graphical form in Table 152 and Figure 75 for the energy allocation results and Table 153 and Figure 76 for the displacement method results. All results are reported based on the IPCC 2007 global warming potentials.

Table 152. Scenario 4 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	79.4	78.5	0.885
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	78.7	79.5	0.835
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.7	79.3	78.5	0.805
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	78.6	79.3	0.64
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	78.7	79.2	0.563
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS_3d	tonne/tonne	0.005	0	0.01	78.7	79.2	0.444
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	79.1	78.7	0.429
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	78.8	79.2	0.371
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	78.8	79.1	0.357
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	78.9	79.1	0.211
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	78.9	79.1	0.206
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	78.9	79	0.164
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	78.9	79.1	0.117
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	79	78.9	0.114

Table 152. Scenario 4 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	78.9	79	0.106
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	775	698	853	78.9	79	0.0894
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	78.9	79	0.0841
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	78.9	79	0.0794
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	78.9	79	0.0383
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	79	79	0.0346
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	79	79	0.0198
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	79	79	0.0185
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	79	79	0.0171
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	79	79	0

Table 153. Scenario 4 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	70.8	72.8	2.02
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	72.4	70.8	1.68
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.7	72.3	70.8	1.53
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	72	70.8	1.25
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	71	72.2	1.21
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS_3d	tonne/tonne	0.005	0	0.01	71.2	72	0.842
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	71.3	72	0.704
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	71.3	71.9	0.678
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	71.3	71.9	0.563
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	71.4	71.8	0.4
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	71.4	71.8	0.356
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	71.5	71.8	0.311
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	71.7	71.5	0.216
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	775	698	853	71.5	71.7	0.17
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	71.5	71.7	0.16
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	71.6	71.7	0.151

Table 153. Scenario 4 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	71.6	71.7	0.117
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	71.6	71.7	0.106
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	71.6	71.6	0.0718
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	71.6	71.6	0.0375
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	71.6	71.6	0.0347
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	71.6	71.6	0.0346
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	71.6	71.6	0.0325
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	71.6	71.6	0

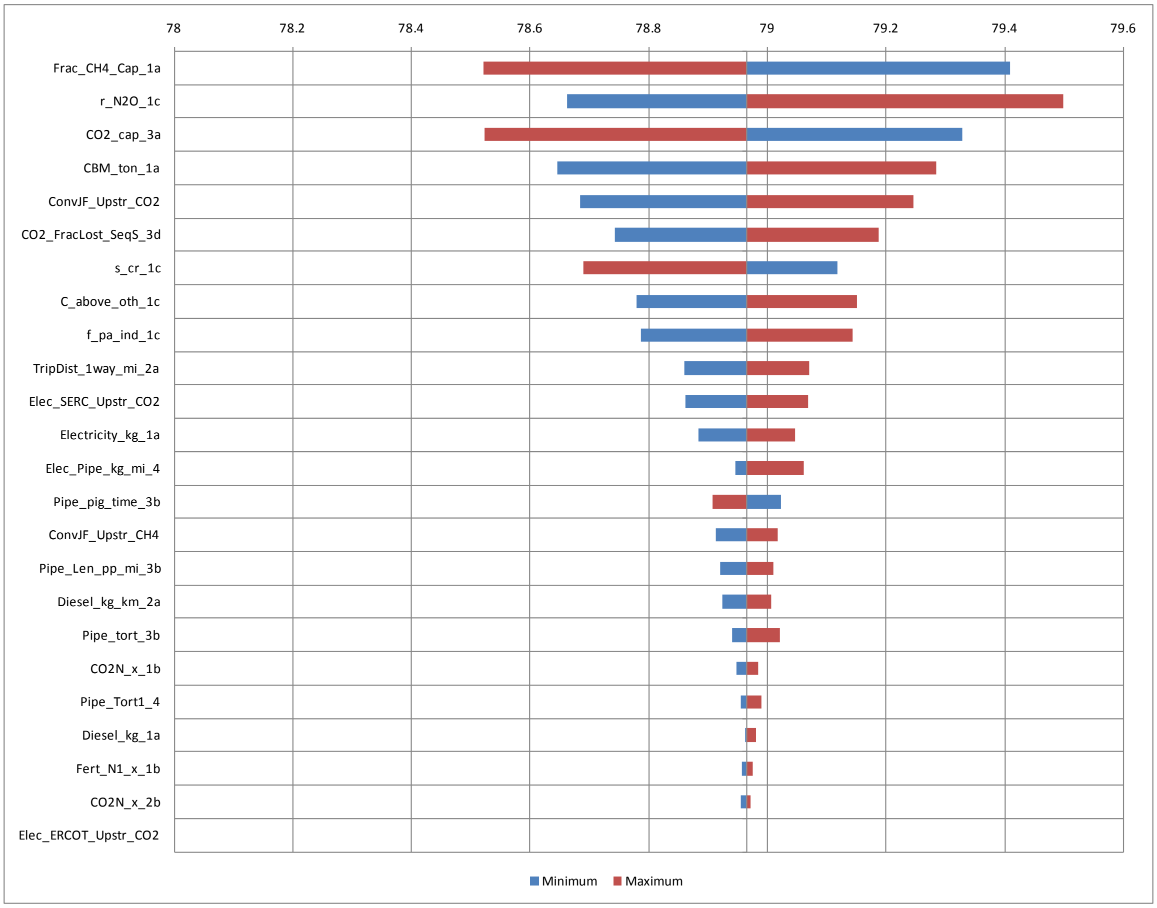


Figure 75. Scenario 4 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

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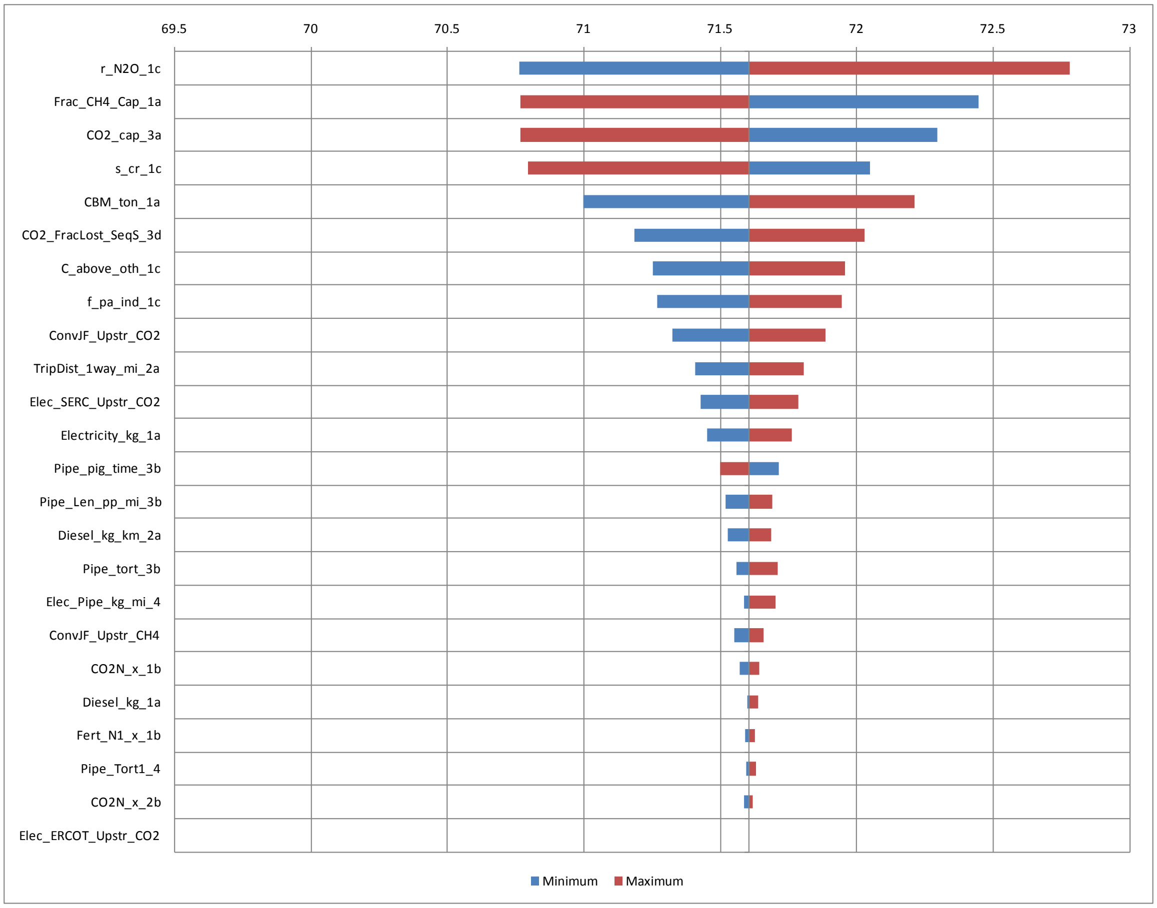


Figure 76. Scenario 4 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

10.4.3 Data Limitations

In terms of broader study limitations, the model boundaries and modeling choices contained in this scenario inform the following study limitations, which should be considered when interpreting final results and conclusions generated from this study:

- **Mine and Mine Methane Emissions:** This scenario presumes that Illinois No. 6 sub-bituminous coal from an underground longwall mine would be used, having an average methane emission rate of 150 scf CH_4/ton with 40 percent capture. Use of an alternative coal type, mine type, methane emission rate, or methane capture rate could increase or decrease mine and mine methane related GHG emissions.
- **Biomass Production:** This scenario presumes that farmed switchgrass would be used as the sole source of biomass. However, alternative sources of biomass could also have been chosen, such as farmed short rotation woody crops or corn stover, or biomass waste streams such as agricultural wastes or logging wastes. The use of alternative farming practices, crop requirements, and/or biomass source could increase or reduce life cycle GHG emissions.

- **Biomass Yields:** This scenario presumes that switchgrass production would yield 4.7 dry tons per acre per year of biomass. However, switchgrass yields reported in the literature are highly variable, in part reflecting farming practices and regional conditions. Higher or lower switchgrass yield values could substantially decrease or increase life cycle land use, respectively.
- **Biomass Transport:** This scenario presumes a 50 mile switchgrass production radius. The intensity of biomass transport emissions is expected to increase with increases in production radius. Therefore, substantial increases in the biomass production radius for this study could result in concurrent increases in transportation related GHG emissions, as well as increases in cost, which under some cases could render a longer distance biomass collection scheme infeasible.
- **CBTL Facility Carbon Capture Rate:** The rate of carbon capture at the F-T facility used for this scenario is 91 percent, which is expected to be a conservative estimate of actual carbon capture rates. However, carbon capture facilities have not been widely implemented at the commercial scale. Therefore, a higher or lower carbon capture rate may apply to some future studies. Increases or decreases in this rate would result in concurrent increases or decreases in life cycle GHG emissions.
- **CBTL Facility Modeling Scenarios:** In order to model the F-T facility, output from a separate ASPEN model was incorporated into the life cycle model used for this study. As a result, the F-T facility model included in this study is static: the workings of the F-T facility cannot be updated or altered to evaluate different F-T facility parameters and setups, without performing substantial additional analysis. The F-T facility results from this study represent specific assumptions, as documented in **Section 6**, and are not necessarily representative of all potential F-T Facility designs.
- **EOR CO_2 Leakage Rates:** This scenario incorporates CO_2 leakage rates of less than one percent. However, actual leakage rates have not been extensively documented, and are expected to be difficult to monitor. Increases in CO_2 leakage rates could result in concurrent increases in life cycle GHG emissions.
- **Pre-Existence of Infrastructure:** Some of the infrastructure needed within the boundary of this study, such as a pipeline network suitable for transferring F-T Jet Fuel to the blending facility, was assumed to be pre-existing. No GHG emissions penalty was included for this infrastructure.
- **Comparative Study Results:** The purpose of this study is to provide a comparative evaluation of alternative fuels against baseline 2005 conventional petroleum jet fuel production and use. Results provided for this scenario reflect life cycle emissions from alternative jet fuel production in comparison to that baseline. However, results from this scenario are not intended to provide absolute GHG emissions values; results from this study should be used with caution, when comparing to life cycle analyses having different baseline assumptions and study goals.

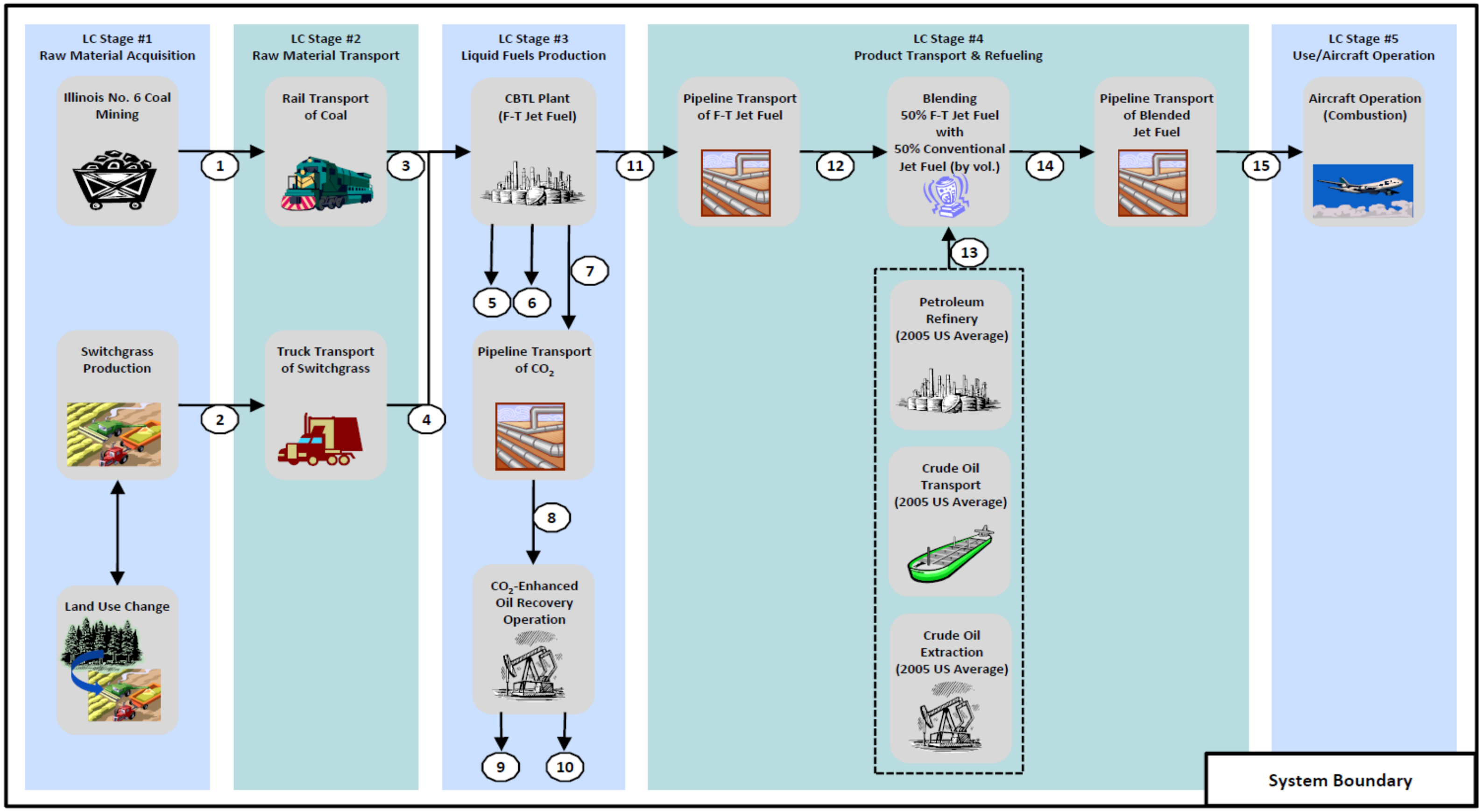
10.5 Scenario 5: 14 Percent Switchgrass, Colbalt F-T Catalyst, EOR (Optimized for Maximum Jet Fuel Production)

10.5.1 Scenario Overview

Scenario 5 was designed to evaluate a CBTL Facility that is optimized for maximum F-T jet fuels production. Feedstocks are derived from a combination of coal (86 percent by weight) and switchgrass (14 percent by weight). Like other scenarios, Scenario 5 assesses a 1:1 blend F-T and conventional jet fuel (US Average) over a period of 30 years. Illinois No. 6 sub-bituminous coal feedstock is shipped via train to a CBTL facility located in Northern Missouri. Regionally-grown and harvested switchgrass is shipped by diesel truck to the same facility, where it is dried and processed. Unlike Scenarios 1-3 and 6-8, the F-T process employed at the CBTL facility uses a cobalt catalyst with autothermal reforming, and with 91 percent flue gas carbon capture. The F-T process produces a combination of F-T jet fuel (80.3 percent by energy) and F-T naphtha (19.7 percent by energy). Note that under Scenario 5, no F-T diesel fuel is produced. Captured carbon dioxide is conveyed via a 775 mile pipeline to the Permian Basin in Texas, where it is used as an injectant in support of CO_2 EOR, and eventually sequestered. The EOR process also results in the production of crude oil and natural gas liquids. Finally, the F-T jet fuel is conveyed via pipeline from the CBTL Facility to a separate blending facility, located at the Woods River Refinery in Illinois. Here it is blended with conventional jet fuel and shipped via pipeline to Chicago O'Hare Airport. Alternatively, the blended fuel may be shipped via a combination of pipeline and tanker truck to Chicago O'Hare and smaller regional airports. Scenario 5 is most closely related to Scenario 10, which also incorporates coal and biomass using cobalt F-T catalyst, using an F-T jet fuels optimized CBTL process. Table 154 provides an overview of key values for Scenario 5.

Table 154. Scenario 5 Overview

Item		Scenario Property		
Study Properties				
Functional Unit		1 MJ of Blended F-T Jet Fuel Consumed		
Blended F-T Jet Fuel		4,010 MJ/bbl		
F-T Jet Fuel		50 percent of final product (by volume)		
Conventional Jet Fuel (US Average)		50 percent of final product (by (volume)		
Temporal Boundary		30 years		
CBTL Facility Properties				
Plant Location		Northern Missouri		
Daily Production Capacity		30,000 bbl/d		
F-T Catalyst Type		Cobalt		
Autothermal Reforming		Yes		
Tail Gas Recycle		Yes		
Carbon Capture		91 percent in flue gas		
Optimized for Maximum F-T Jet Fuel Production		Yes		
Item	**Value**	**Units**	**Value**	**Units**
Energy Feedstock Inputs to CBTL Facility				
Coal, Illinois No. 6	11,889	short tons/day	86%	percent by mass
Biomass, Switchgrass	1,602	short tons/day	14%	percent by mass
Product Outputs from CBTL Plant				
CBTL Plant Liquid Product Output	30,000	bbl/d	100%	percent by energy
CBTL Plant F-T Jet Fuel Production	23,595	bbl/d	80.3%	percent by energy
CBTL Plant F-T-Diesel Fuel Production	0	bbl/d	0%	percent by energy
CBTL Plant F-T Naphtha Production	6,405	bbl/d	19.7%	percent by energy
Carbon Management Strategy: CO_2-Enhanced Oil Recovery (CO_2-EOR)				
Storage Location	Permian Basin, TX		775	miles from CBTL Facility
Carbon Dioxide Sequestered	15,864	short tons/day	99.5%	percent of CO_2 received
Crude Oil Production	63,440	bbl/d	97.3%	percent by energy
Natural Gas Liquids Production	2,928	bbl/d	2.7%	percent by energy
Carbon Management Strategy: Saline Aquifer				
Storage Location	N/A		N/A	N/A
Carbon Dioxide Sequestered	N/A	N/A	N/A	N/A
Product Transport to Airport				
F-T Jet Fuel Pipeline Transport to Wood River, Il Refinery	32,096	bbl/d	225	miles
Blended F-T Jet Fuel Pipeline Transport to Chicago O'Hare Airport	33,079	bbl/d	245	miles



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (dry)	37.0	g/MJ LHV	6	F-T Naphtha	2.7	g/MJ LHV	11	F-T Jet Fuel	11.0	g/MJ LHV
2	Switchgrass (dry)	5.61	g/MJ LHV	7	Supercritical CO_2	56.8	g/MJ LHV	12	F-T Jet Fuel	11.0	g/MJ LHV
3	Illinois No. 6 Coal (dry)	37.0	g/MJ LHV	8	Supercritical CO_2	56.3	g/MJ LHV	13	Conv. Jet Fuel	11.8	g/MJ LHV
4	Switchgrass (dry)	5.61	g/MJ LHV	9	Crude Oil	34.3	g/MJ LHV	14	Blended Jet Fuel	22.8	g/MJ LHV
5	F-T Diesel	0	g/MJ LHV	10	Natural Gas Liquids	0.869	g/MJ LHV	15	Blended Jet Fuel	22.8	g/MJ LHV

Figure 77. Scenario 5: System Boundary and Major Flows (g/MJ Jet Fuel Combusted, LHV)

10.5.2 Life Cycle GHG Results

Lifecycle GHG results are presented below for the deterministic analysis using the best estimate for each modeling parameter, probabilistic uncertainty analysis using the defined uncertainty ranges and probability distributions sampled approximately 2,000 times using a Monte Carlo simulation, and sensitivity analysis to determine the key modeling parameters within the life cycle with greatest influence on the results.

10.5.2.1 Deterministic Analysis Results

Allocated results are tabulated in terms of life cycle sub-categories in Table 155 for both energy allocation and system expansion/displacement allocation method. Total unallocated CO_2e emissions are also provided along with each allocated result to assist understanding of the effect of allocation on each final result. The unallocated results do not represent the life cycle GHG result for 1 MJ of blended F-T Jet Fuel consumed. Unallocated results represent the total GHG emissions released to the atmosphere to produce the suite of co-products produced within the study boundary.

Table 155. Scenario 5 Deterministic Analysis Results (Using IPCC 2007 GWP)

Life Cycle Stage Sub-categories	Unallocated CO_2e Emissions[1]		CO_2e Emissions Allocated by Energy		CO_2e Emissions Allocated by Displacement	
	g/MJ	%	g/MJ	%	g/MJ	%
LC Stage 1a: Illinois No. 6 Coal Acquisition	3.3	3.3%	0.7	0.8%	2.3	2.6%
LC Stage 2a: Coal Transport	0.6	0.6%	0.1	0.1%	0.4	0.5%
LC Stage 1b: Switchgrass Biomass Production	-9.1	-9.1%	-2.1	-2.5%	-11.8	-13.4%
LC Stage 1c: Direct Land Use	-0.2	-0.2%	0	0.0%	-0.3	-0.3%
LC Stage 1c: Indirect Land Use	0.9	0.9%	0.2	0.2%	0.6	0.7%
LC Stage 2b: Switchgrass Transport	0.2	0.2%	0	0.0%	0.2	0.2%
LC Stage 3a: CBTL Facility	6.9	6.9%	1.6	1.9%	4.9	5.6%
LC Stage 3b: Supercritical CO_2 Transport	0.6	0.6%	0.1	0.1%	0.4	0.5%
LC Stage 3c: Enhanced Oil Recovery (EOR)	18	18.1%	4.1	4.9%	12.7	14.5%
LC Stage 3d: Supercritical CO_2 Sequestration	0	0.0%	0	0.0%	0	0.0%
LC Stage 4: F-T Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 4: Conventional Jet Fuel Life Cycle	6.9	6.9%	6.9	8.3%	6.9	7.9%
LC Stage 4: Blended Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 5: Jet Fuel Use	71.3	71.7%	71.3	85.7%	71.3	81.2%
Life Cycle Total:	99.5	100.0%	83.2	100.0%	87.8	100.0%

1. Unallocated results represent all co-products produced within the system boundary therefore do not represent the life cycle GHG results for 1 MJ of blended F-T jet fuel consumed. The unallocated results are presented only to illustrate the effect of allocation.

The deterministic analysis results in a 5 percent reduction in life cycle GHG emissions in comparison to a conventional jet fuel baseline of 87.4 g CO_2e/MJ jet fuel combusted, LHV when allocated by energy. Allocation of the co-products using the displacement method results a less than 0.5 percent increase in the life cycle GHG profile compared to conventional jet fuel baseline. Thus the deterministic results of this study show that the life cycle GHG profile for Scenario 5 is 5 percent below to essentially equivalent to the conventional jet fuel baseline.

Results by life cycle stage contribution show that fuel combustion (use phase) accounts for the majority of life cycle GHG emissions for both energy allocation (86 percent of total life cycle

emissions) and displacement (81 percent of total lifecycle emissions) respectively. Excluding the use phase, the upstream life cycle stage with the next highest life cycle GHG emissions contribution does not differ by the method of co-product allocation. The next largest emissions contributor for the allocation by energy method is the conventional jet fuel production life cycle followed by EOR operation. Allocation by displacement method reverses this, with EOR operation followed by conventional jet fuel production life cycle as the next most significant contributors. Interestingly, the CBTL facility contributes only 1.9 percent to 5.6 percent to the total life cycle GHG profile, depending on method of allocation.

10.5.2.2 Probabilistic Uncertainty Analysis Results

Table 156 presents summary statistics for probabilistic CO_2e emissions for Scenario 5 (14 percent switchgrass, cobalt F-T catalyst, maximize production of F-T jet fuel and EOR) along with the "best estimate" (i.e., the deterministic result). Figure 78 presents the probabilistic results in a "box and whisker" plot. Table 156 has the same structure as Table 141, while Figure 78 has the same structure as Figure 66**.**

As discussed in **Section 6**, using a cobalt catalyst enables the CBTL facility to be operated in a manner that maximizes F-T jet fuel production. As shown for Scenario 5, doing so results in lifecycle CO_2e emissions that are slightly higher than conventional jet fuel for displacement allocation, but lower than jet fuel for energy allocation. Specifically, median emissions for energy allocation are 4.3 g CO_2e/MJ LHV lower than conventional jet fuel, while median emissions for displacement allocation are 0.1 g CO_2e/MJ LHV higher than conventional jet fuel. The distribution for the combined result therefore spans conventional jet fuel emissions, with over 60 percent of the combined distribution is below conventional jet fuel emissions for Scenario 5.

Table 156. Scenario 5 Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

Quantity	CO_2e Emissions Allocated by Energy (g CO_2e/MJ LHV)	CO_2e Emissions Allocated by Displacement (g CO_2e/MJ LHV)	Combined CO_2e Emissions (g CO_2e/MJ LHV)
Minimum	82.7	86.0	82.7
25^{th} Percentile	83.1	87.3	83.3
Median	83.2	87.8	86.6
75^{th} Percentile	83.4	88.3	87.8
Maximum	83.9	89.9	89.9
Best Estimate	83.2	87.7	85.5
Conventional Jet Fuel	87.4	87.4	87.4

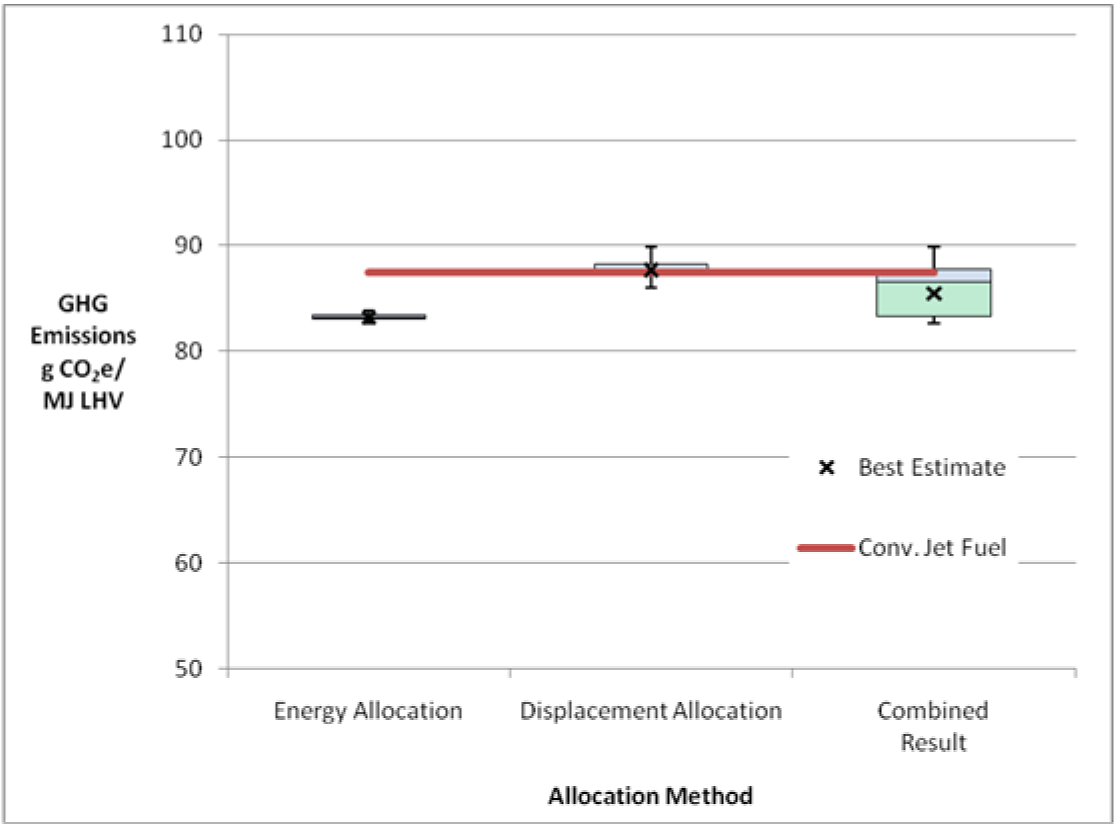


Figure 78. Scenario 5 Box and Whisker Plot of Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

10.5.2.3 Sensitivity Analysis Results

Sensitivity analysis results were calculated for both co-product allocation procedures (energy allocation and displacement method) by adjusting each modeling parameter independently between the minimum and maximum values to determine the effect on the final life cycle GHG result. The 24 modeling parameters with the greatest effect on the results was determined and ranked from highest to lowest based on their absolute difference. The results are reported in both tabular and graphical form in Table 157 and Figure 79 for the energy allocation results and Table 158 and Figure 80 for the displacement method results. All results are reported based on the IPCC 2007 global warming potentials.

Table 157. Scenario 5 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	79.9	80.4	0.563
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	80	80.5	0.507
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	80.2	80	0.26
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.7	80.3	80	0.25
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	80	80.3	0.225
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	80.3	80	0.221
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	80	80.3	0.217
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	80.1	80.2	0.171
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	80.1	80.2	0.16
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air_3c	kg/kg	0.005	0	0.01	80.1	80.2	0.127
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	80.1	80.3	0.117
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	80.1	80.2	0.106
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	80.1	80.2	0.0838
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	80.1	80.2	0.0527
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	80.1	80.2	0.0409

Table 157. Scenario 5 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) ***(Cont'd)***

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	80.1	80.2	0.0346
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	80.1	80.2	0.0233
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	80.1	80.2	0.021
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	80.1	80.2	0.0112
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	80.1	80.2	0.0104
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	80.2	80.2	0.00494
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	80.2	80.2	0.00419
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	100	90	110	80.2	80.2	0.00329
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	80.2	80.2	0.00293

Table 158. Scenario 5 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
N2O emissions from nitrogen fertilizer	r_N2O_1c	kg N2O/kg N	0.02	0.003	0.05	64.4	68.9	4.48
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	67.4	64.5	2.87
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.7	67.2	65.5	1.66
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	65.6	67.1	1.49
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	67.1	65.6	1.46
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	65.6	67.1	1.44
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	65.8	66.9	1.13
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	65.8	66.9	1.06
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air_3c	kg/kg	0.005	0	0.01	65.9	66.8	0.842
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	66.1	66.6	0.563
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	66.2	66.5	0.349
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	66.2	66.5	0.335
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	66.2	66.5	0.271
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	66.3	66.4	0.152
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	66.3	66.4	0.139

Table 158. Scenario 5 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) ***(Cont'd)***

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	66.3	66.5	0.117
Upstream CH4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH4/kWh	0.00361	0.00343	0.00379	66.3	66.4	0.106
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	66.3	66.4	0.0735
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	66.3	66.4	0.0689
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	66.4	66.4	0.0346
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	66.4	66.4	0.0327
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	66.4	66.3	0.0277
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	100	90	110	66.3	66.4	0.0218
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	66.4	66.4	0.0194

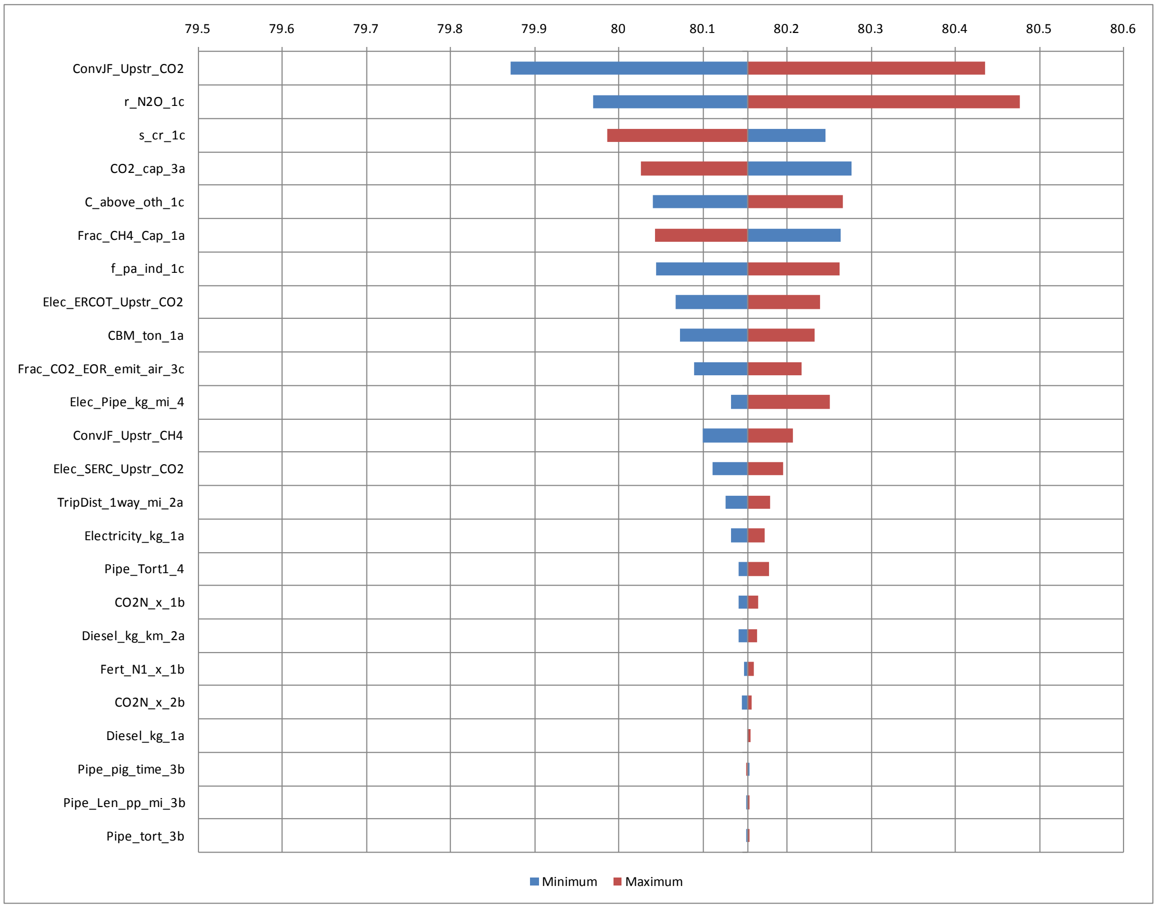


Figure 79. Scenario 5 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

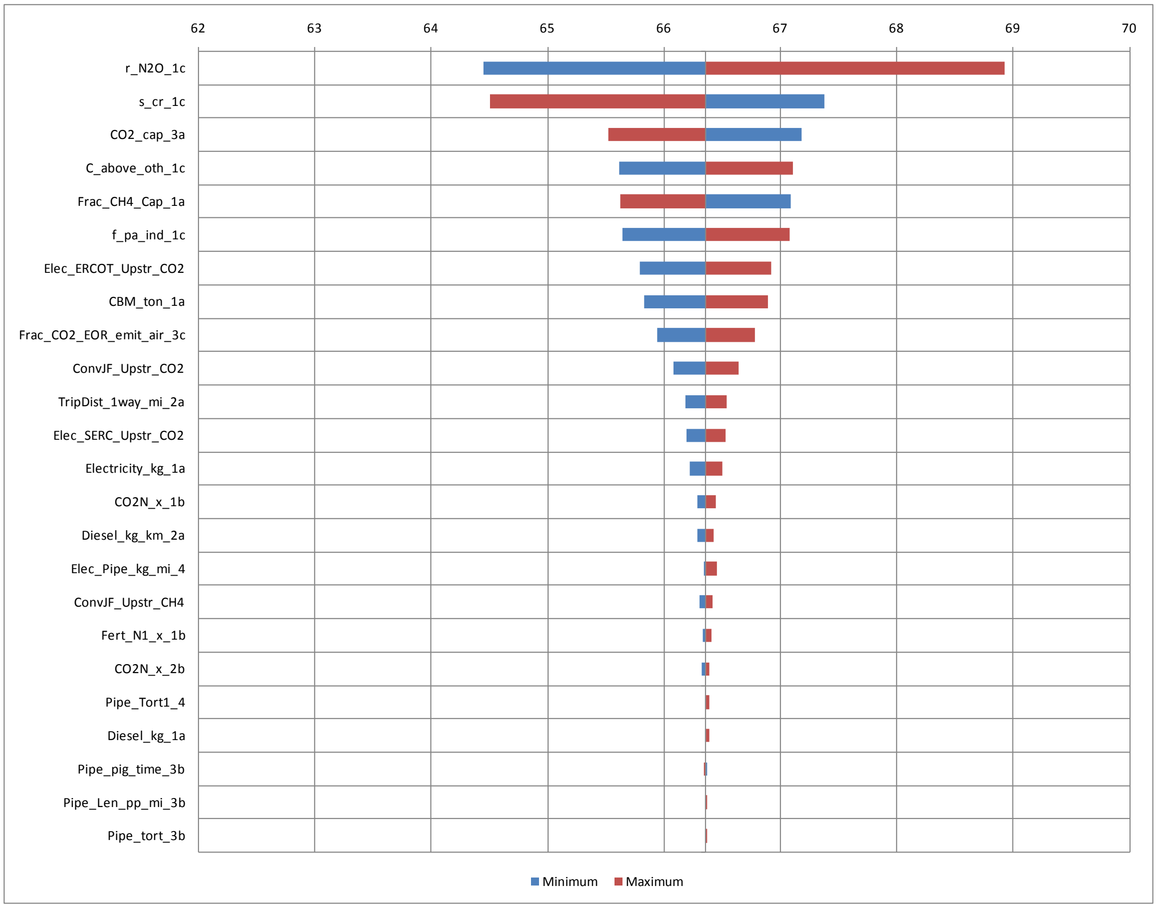


Figure 80. Scenario 5 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

10.5.3 Data Limitations

In terms of broader study limitations, the model boundaries and modeling choices contained in this scenario inform the following study limitations, which should be considered when interpreting final results and conclusions generated from this study:

- **Mine and Mine Methane Emissions:** This scenario presumes that Illinois No. 6 sub-bituminous coal from an underground longwall mine would be used, having an average methane emission rate of 150 scf CH_4/ton with 40 percent capture. Use of an alternative coal type, mine type, methane emission rate, or methane capture rate could increase or decrease mine and mine methane related GHG emissions.
- **Biomass Production:** This scenario presumes that farmed switchgrass would be used as the sole source of biomass. However, alternative sources of biomass could also have been chosen, such as farmed short rotation woody crops or corn stover, or biomass waste streams such as agricultural wastes or logging wastes. The use of alternative farming practices, crop requirements, and/or biomass source could increase or reduce life cycle GHG emissions.

- **Biomass Yields:** This scenario presumes that switchgrass production would yield 4.7 dry tons per acre per year of biomass. However, switchgrass yields reported in the literature are highly variable, in part reflecting farming practices and regional conditions. Higher or lower switchgrass yield values could substantially decrease or increase life cycle land use, respectively.
- **Biomass Transport:** This scenario presumes a 50 mile switchgrass production radius. The intensity of biomass transport emissions is expected to increase with increases in production radius. Therefore, substantial increases in the biomass production radius for this study could result in concurrent increases in transportation related GHG emissions, as well as increases in cost, which under some cases could render a longer distance biomass collection scheme infeasible.
- **CBTL Facility Carbon Capture Rate:** The rate of carbon capture at the F-T facility used for this scenario is 91 percent, which is expected to be a conservative estimate of actual carbon capture rates. However, carbon capture facilities have not been widely implemented at the commercial scale. Therefore, a higher or lower carbon capture rate may apply to some future studies. Increases or decreases in this rate would result in concurrent increases or decreases in life cycle GHG emissions.
- **CBTL Facility Modeling Scenarios:** In order to model the F-T facility, output from a separate ASPEN model was incorporated into the life cycle model used for this study. As a result, the F-T facility model included in this study is static: the workings of the F-T facility cannot be updated or altered to evaluate different F-T facility parameters and setups, without performing substantial additional analysis. The F-T facility results from this study represent specific assumptions, as documented in **Section 6**, and are not necessarily representative of all potential F-T Facility designs.
- **EOR CO_2 Sequestration Leakage Rates:** This scenario incorporates CO_2 leakage rates of less than one percent. However, actual leakage rates have not been extensively documented, and are expected to be difficult to monitor. Increases in CO_2 leakage rates could result in concurrent increases in life cycle GHG emissions.
- **Pre-Existence of Infrastructure:** Some of the infrastructure needed within the boundary of this study, such as a pipeline network suitable for transferring F-T Jet Fuel to the blending facility, was assumed to be pre-existing. No GHG emissions penalty was included for this infrastructure.
- **Comparative Study Results:** The purpose of this study is to provide a comparative evaluation of alternative fuels against baseline 2005 conventional petroleum jet fuel production and use. Results provided for this scenario reflect life cycle emissions from alternative jet fuel production in comparison to that baseline. However, results from this scenario are not intended to provide absolute GHG emissions values; results from this study should be used with caution, when comparing to life cycle analyses having different baseline assumptions and study goals.

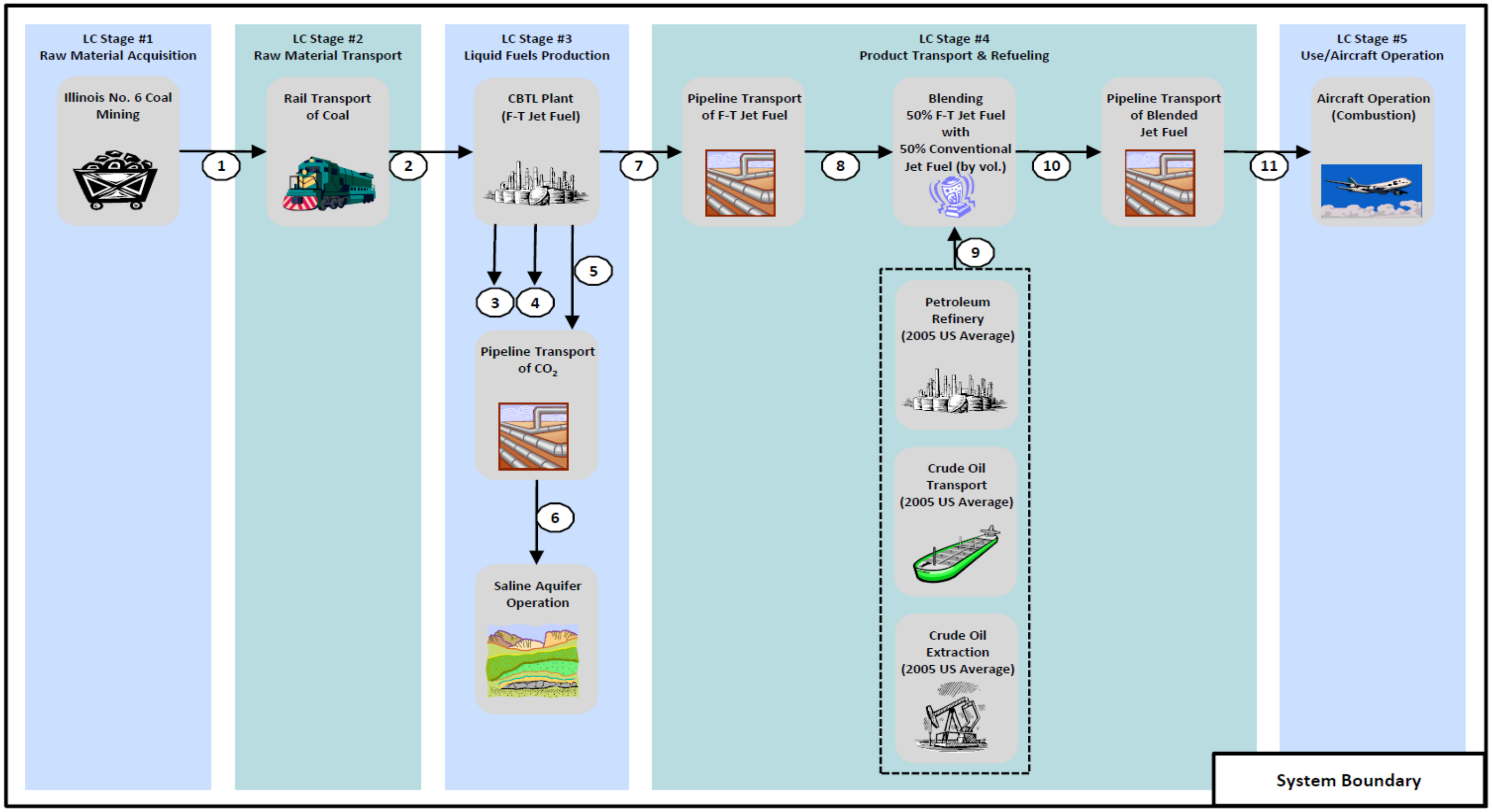
10.6 Scenario 6: 0 Percent Switchgrass, Iron F-T Catalyst, Saline Aquifer Sequestration

10.6.1 Scenario Overview

Scenario 6 was designed to evaluate F-T fuels derived solely from coal feedstock. Like other scenarios, Scenario 2 assesses a 1:1 blend F-T and conventional jet fuel (US Average) over a period of 30 years. Illinois No. 6 sub-bituminous coal feedstock is processed at a CBTL facility located in Northern Missouri. The F-T process employed at the facility uses an iron catalyst without autothermal reforming, and with 91 percent flue gas carbon capture. The F-T process produces a combination of F-T jet fuel (52.9 percent by energy), F-T diesel (37.3 percent by energy), and F-T naphtha (9.83 percent by energy). Captured carbon dioxide is conveyed via a 100 mile pipeline to a saline aquifer carbon dioxide sequestration site where it is injected into the ground and eventually sequestered. Finally, the F-T jet fuel is conveyed via pipeline from the CBTL Facility to a separate blending facility, located at the Woods River Refinery in Illinois. Here it is blended with conventional jet fuel and shipped via pipeline to Chicago O'Hare Airport. Alternatively, the blended fuel may be shipped via a combination of pipeline and tanker truck to Chicago O'Hare and smaller regional airports. Scenario 6 is most similar to Scenario 1, which also relies solely on coal as feedstock, and uses an iron F-T catalyst. Table 159 provides an overview of key values for Scenario 6.

Table 159. Scenario 6 Overview

Item	Scenario Property			
Study Properties				
Functional Unit	1 MJ of Blended F-T Jet Fuel Consumed			
Blended F-T Jet Fuel	4,010 MJ/bbl			
F-T Jet Fuel	50 percent of final product (by volume)			
Conventional Jet Fuel (US Average)	50 percent of final product (by (volume)			
Temporal Boundary	30 years			
CBTL Facility Properties				
Plant Location	Northern Missouri			
Daily Production Capacity	30,000 bbl/d			
F-T Catalyst Type	Iron			
Autothermal Reforming	No			
Tail Gas Recycle	Yes			
Carbon Capture	91 percent in flue gas			
Optimized for Maximum F-T Jet Fuel Production	No			
Item	**Value**	**Units**	**Value**	**Units**
Energy Feedstock Inputs to CBTL Facility				
Coal, Illinois No. 6	12,728	short tons/day	100%	percent by energy
Biomass, Switchgrass	0	short tons/day	0%	percent by energy
Product Outputs from CBTL Plant				
CBTL Plant Liquid Product Output	30,000	bbl/d	100%	percent by energy
CBTL Plant F-T Jet Fuel Production	15,939	bbl/d	52.9%	percent by energy
CBTL Plant F-T-Diesel Fuel Production	10,769	bbl/d	37.3%	percent by energy
CBTL Plant F-T Naphtha Production	3,292	bbl/d	9.83%	percent by energy
Carbon Management Strategy: CO_2-Enhanced Oil Recovery (CO_2-EOR)				
Storage Location	N/A		N/A	N/A
Carbon Dioxide Sequestered	N/A	N/A	N/A	N/A
Crude Oil Production	N/A	N/A	N/A	N/A
Natural Gas Liquids Production	N/A	N/A	N/A	N/A
Carbon Management Strategy: Saline Aquifer				
Storage Location	Relative to CBTL Facility		100	miles from CBTL Facility
Carbon Dioxide Sequestered	15,889	short tons/day	99.5%	percent of CO_2 received
Product Transport to Airport				
F-T Jet Fuel Pipeline Transport to Wood River, Il Refinery	21,595	bbl/d	225	miles
Blended F-T Jet Fuel Pipeline Transport to Chicago O'Hare Airport	22,346	bbl/d	245	miles



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (dry)	59.3	g/MJ LHV	6	Supercritical CO_2	83.2	g/MJ LHV	11	Blended Jet Fuel	22.8	g/MJ LHV
2	Illinois No. 6 Coal (dry)	59.3	g/MJ LHV	7	F-T Jet Fuel	11.0	g/MJ LHV	12			
3	F-T Diesel	7.75	g/MJ LHV	8	F-T Jet Fuel	11.0	g/MJ LHV	13			
4	F-T Naphtha	2.04	g/MJ LHV	9	Conv. Jet Fuel	11.8	g/MJ LHV	14			
5	Supercritical CO_2	83.7	g/MJ LHV	10	Blended Jet Fuel	22.8	g/MJ LHV	15			

Figure 81. Scenario 6: System Boundary and Major Flows (g/MJ Jet Fuel Combusted, LHV)

10.6.2 Life Cycle GHG Results

Lifecycle GHG results are presented below for the deterministic analysis using the best estimate for each modeling parameter, probabilistic uncertainty analysis using the defined uncertainty ranges and probability distributions sampled approximately 2,000 times using a Monte Carlo simulation, and sensitivity analysis to determine the key modeling parameters within the life cycle with greatest influence on the results.

10.6.2.1 Deterministic Analysis Results

Allocated results are tabulated in terms of life cycle sub-categories in Table 160 for both energy allocation and system expansion/displacement allocation method. Total unallocated CO_2e emissions are also provided along with each allocated result to assist understanding of the effect of allocation on each final result. The unallocated results do not represent the life cycle GHG result for 1 MJ of blended F-T Jet Fuel consumed. Unallocated results represent the total GHG emissions released to the atmosphere to produce the suite of co-products produced within the study boundary.

Table 160. Scenario 6 Deterministic Analysis Results (Using IPCC 2007 GWP)

Life Cycle Stage Sub-categories	Unallocated CO_2e Emissions[1]		CO_2e Emissions Allocated by Energy		CO_2e Emissions Allocated by Displacement	
	g/MJ	%	g/MJ	%	g/MJ	%
LC Stage 1a: Illinois No. 6 Coal Acquisition	5.2	5.6%	2.8	3.2%	2.6	3.0%
LC Stage 2a: Coal Transport	0.9	1.0%	0.5	0.6%	0.4	0.5%
LC Stage 1b: Switchgrass Biomass Production	0	0.0%	0	0.0%	0	0.0%
LC Stage 1c: Direct Land Use	0	0.0%	0	0.0%	0	0.0%
LC Stage 1c: Indirect Land Use	0	0.0%	0	0.0%	0	0.0%
LC Stage 2b: Switchgrass Transport	0	0.0%	0	0.0%	0	0.0%
LC Stage 3a: CBTL Facility	8.4	9.0%	4.5	5.2%	4.2	4.9%
LC Stage 3b: Supercritical CO_2 Transport	0	0.0%	0	0.0%	0	0.0%
LC Stage 3c: Enhanced Oil Recovery (EOR)	0	0.0%	0	0.0%	0	0.0%
LC Stage 3d: Supercritical CO_2 Sequestration	0.5	0.5%	0.3	0.3%	0.3	0.3%
LC Stage 4: F-T Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 4: Conventional Jet Fuel Life Cycle	6.9	7.4%	6.9	8.0%	6.9	8.0%
LC Stage 4: Blended Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 5: Jet Fuel Use	71.4	76.3%	71.4	82.5%	71.4	83.0%
Life Cycle Total:	93.6	100.0%	86.5	100.0%	86	100.0%

1. Unallocated results represent all co-products produced within the system boundary therefore do not represent the life cycle GHG results for 1 MJ of blended F-T jet fuel consumed. The unallocated results are presented only to illustrate the effect of allocation.

The deterministic analysis results in a 1 percent reduction in life cycle GHG emissions in comparison to a conventional jet fuel baseline of 87.4 g CO_2e/MJ jet fuel combusted, LHV when allocated by energy. Allocation of the co-products using the displacement method results a 2 percent reduction in the life cycle GHG profile compared to conventional jet fuel baseline. Thus the deterministic results of this study show that the life cycle GHG profile for Scenario 6 is 2 percent to 1 percent below the conventional jet fuel baseline.

Results by life cycle stage contribution show that fuel combustion (use phase) accounts for the majority of life cycle GHG emissions for both energy allocation (83 percent of total life cycle

emissions) and displacement (83 percent of total lifecycle emissions) respectively. Excluding the use phase, the upstream life cycle stage with the next highest life cycle GHG contribution does not differ by the method of co-product allocation. The next largest contributor for both allocation methods is the conventional jet fuel production life cycle followed by CBTL operation. Interestingly, the CBTL facility contributes only 4.9 percent to 5.2 percent to the total life cycle GHG profile, depending on method of allocation.

10.6.2.2 Probabilistic Uncertainty Analysis Results

Table 161 presents summary statistics for probabilistic CO_2e emissions for Scenario 6 (0 percent switchgrass, iron F-T catalyst, normal product slate, and sequestration) along with the "best estimate" (i.e., the deterministic result). Figure 82 presents the probabilistic results in a "box and whisker" plot. Scenario 6 provides a convenient comparison point to Scenario 1: Scenario 6 includes CO_2 sequestration as a carbon management strategy, rather than CO_2 EOR. As shown, median CO_2e emissions values are slightly below conventional jet fuel emissions for both energy and displacement allocation. Specifically, median emissions under energy allocation are lower by 0.9 g CO_2e/MJ LHV, while median emissions under displacement allocation are lower by 1.0 g CO_2e/MJ LHV. For both energy and displacement allocation, over 75 percent of the distribution of CO_2e emissions is below the conventional jet fuel value. However, for both types of allocation, estimated maximum emissions values would slightly exceed lifecycle CO_2e for conventional jet fuel, by up to 1.2 g CO_2e/MJ LHV for displacement allocation.

Table 161. Scenario 6 Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

Quantity	CO_2e Emissions Allocated by Energy (g CO_2e/MJ LHV)	CO_2e Emissions Allocated by Displacement (g CO_2e/MJ LHV)	Combined CO_2e Emissions (g CO_2e/MJ LHV)
Minimum	85.2	83.6	83.6
25th Percentile	86.2	85.4	85.9
Median	86.5	86.0	86.4
75th Percentile	86.9	86.6	86.8
Maximum	87.9	88.6	88.6
Best Estimate	86.5	86.0	86.25
Conventional Jet Fuel	87.4	87.4	87.4

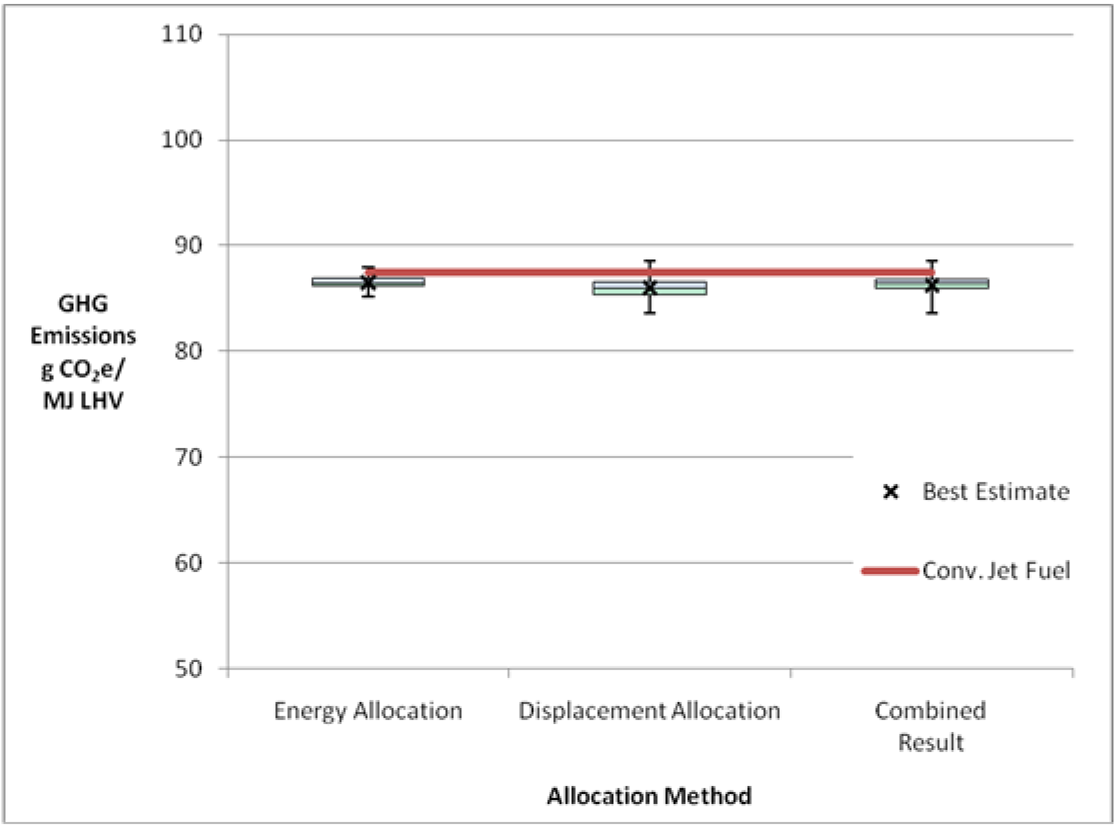


Figure 82. Scenario 6 Box and Whisker Plot of Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

10.6.2.3 Sensitivity Analysis Results

Sensitivity analysis results were calculated for both co-product allocation procedures (energy allocation and displacement method) by adjusting each modeling parameter independently between the minimum and maximum values to determine the effect on the final life cycle GHG result. The 24 modeling parameters with the greatest effect on the results was determined and ranked from highest to lowest based on their absolute difference. The results are reported in both tabular and graphical form in Table 162 and Figure 83 for the energy allocation results and Table 163 and Figure 84 for the displacement method results. All results are reported based on the IPCC 2007 global warming potentials.

Table 162. Scenario 6 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	70	71.8	1.77
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	71	70.1	0.909
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.69	71	70.2	0.805
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	70.3	71.1	0.785
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	71.1	70.3	0.771
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	70.3	71.1	0.756
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	70.4	71	0.563
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	70.4	71	0.558
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS _3d	tonne/tonne	0.005	0	0.01	70.5	70.9	0.444
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_C O2	kg CO_2/kWh	0.762	0.686	0.838	70.6	70.8	0.195
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	70.6	70.8	0.184
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	70.6	70.8	0.143
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	70.7	70.8	0.117
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	70.7	70.6	0.114

Table 162. Scenario 6 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	70.6	70.7	0.106
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	775	698	853	70.6	70.7	0.0894
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	70.6	70.7	0.0811
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	70.7	70.7	0.0794
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	70.6	70.7	0.0733
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	70.7	70.7	0.0392
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	70.7	70.7	0.0363
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	70.7	70.7	0.0346
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	70.7	70.7	0.0172
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	70.7	70.7	0

Table 163. Scenario 6 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	54.4	58.3	3.92
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	56.7	54.4	2.3
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.69	56.6	55.1	1.53
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	55.2	56.7	1.49
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	56.7	55.2	1.46
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	55.2	56.6	1.43
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	55.4	56.5	1.06
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS _3d	tonne/tonne	0.005	0	0.01	55.5	56.3	0.841
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	55.6	56.2	0.563
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	55.8	56.1	0.348
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_C O2	kg CO_2/kWh	0.762	0.686	0.838	55.8	56.1	0.334
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	55.8	56.1	0.271
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	56	55.8	0.216
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	775	698	853	55.8	56	0.169
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	55.9	56	0.152

Table 163. Scenario 6 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) ***(Cont'd)***

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	55.9	56	0.15
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	55.9	56	0.139
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	55.9	56	0.117
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	55.9	56	0.106
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	55.9	56	0.0736
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	55.9	56	0.0688
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	55.9	56	0.0346
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	55.9	56	0.0327
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	55.9	55.9	0

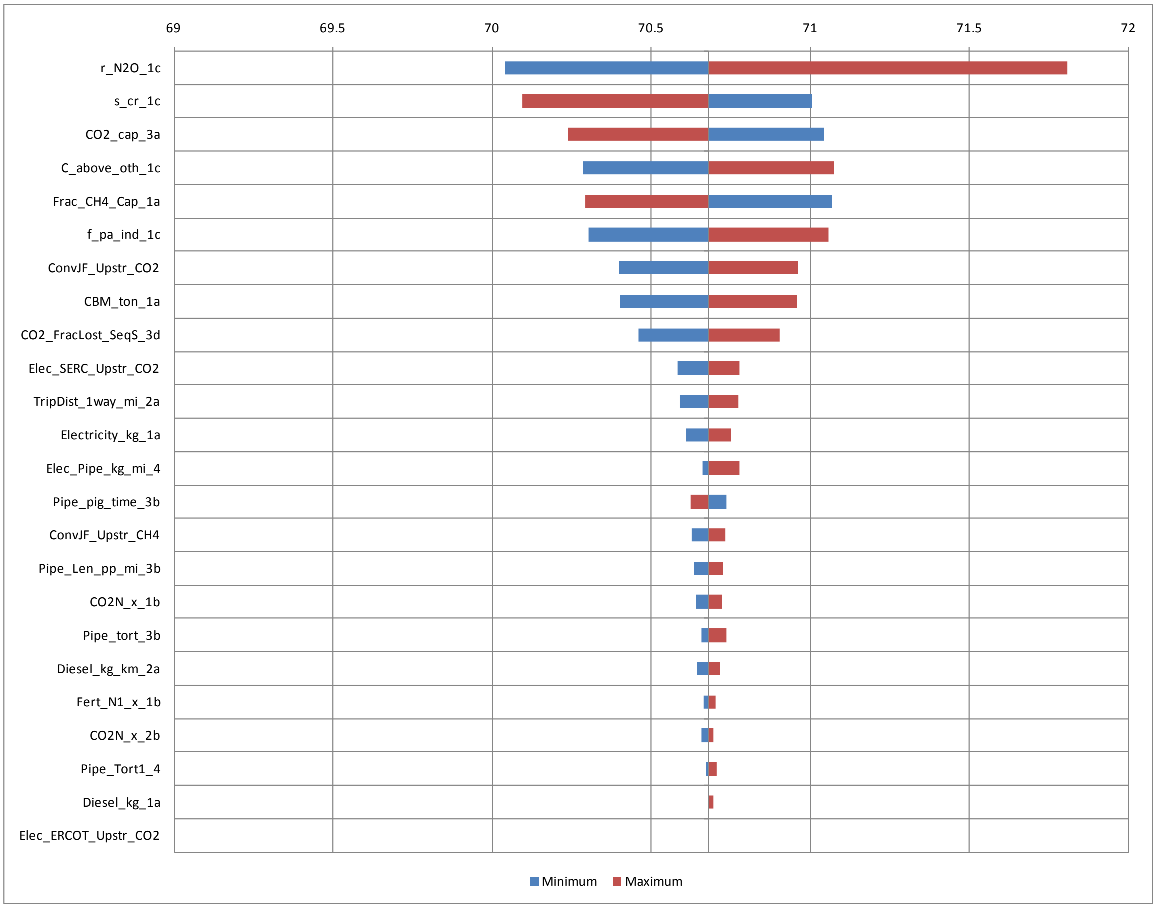


Figure 83. Scenario 6 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

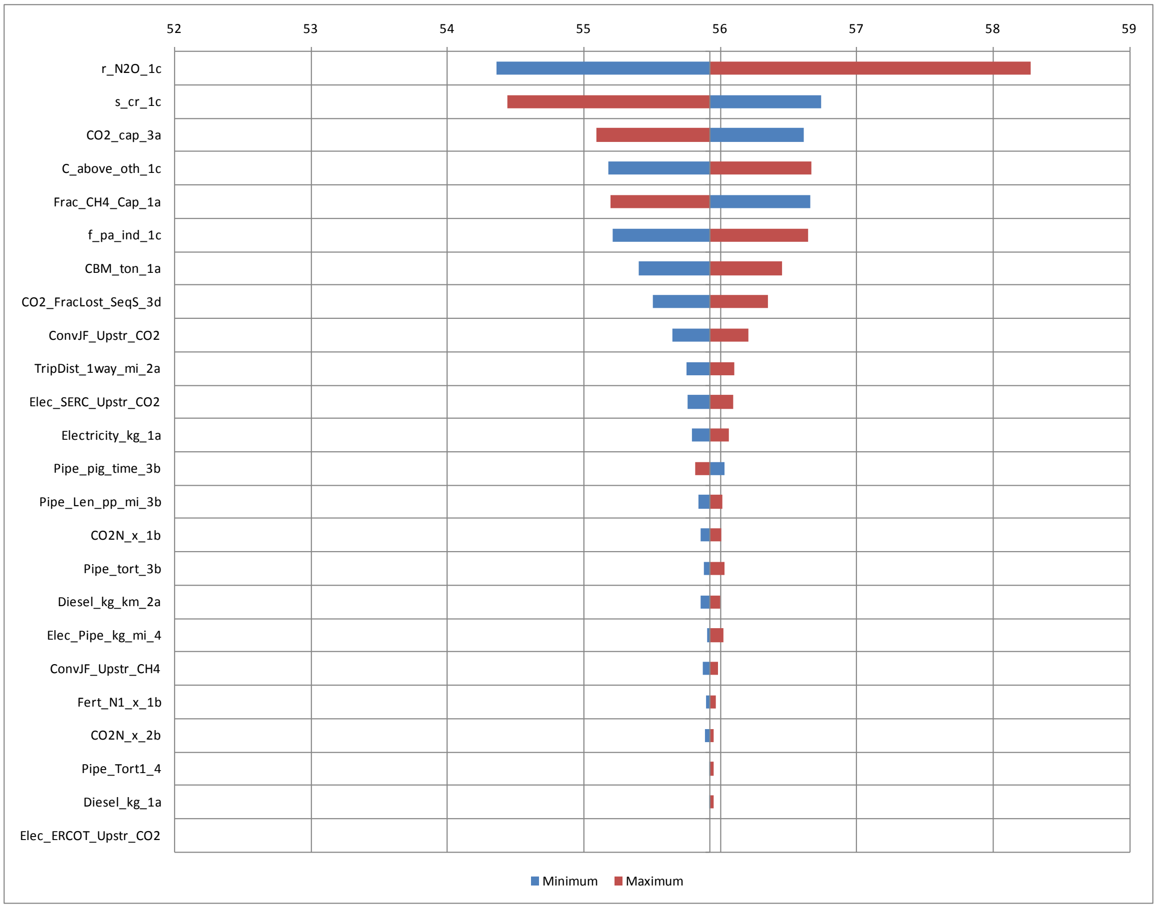


Figure 84. Scenario 6 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

10.6.3 Data Limitations

In terms of broader study limitations, the model boundaries and modeling choices contained in this scenario inform the following study limitations, which should be considered when interpreting final results and conclusions generated from this study:

- **Mine and Mine Methane Emissions:** This scenario presumes that Illinois No. 6 sub-bituminous coal from an underground longwall mine would be used, having an average methane emission rate of 150 scf CH_4/ton with 40 percent capture. Use of an alternative coal type, mine type, methane emission rate, or methane capture rate could increase or decrease mine and mine methane related GHG emissions.
- **CBTL Facility Carbon Capture Rate:** The rate of carbon capture at the F-T facility used for this scenario is 91 percent, which is expected to be a conservative estimate of actual carbon capture rates. However, carbon capture facilities have not been widely implemented at the commercial scale. Therefore, a higher or lower carbon capture rate may apply to some future studies. Increases or decreases in this rate would result in concurrent increases or decreases in life cycle GHG emissions.

- **CBTL Facility Modeling Scenarios:** In order to model the F-T facility, output from a separate ASPEN model was incorporated into the life cycle model used for this study. As a result, the F-T facility model included in this study is static: the workings of the F-T facility cannot be updated or altered to evaluate different F-T facility parameters and setups, without performing substantial additional analysis. The F-T facility results from this study represent specific assumptions, as documented in **Section 6**, and are not necessarily representative of all potential F-T Facility designs.
- **Saline Sequestration Leakage Rates:** This scenario incorporates CO_2 leakage rates of less than one percent. However, actual leakage rates have not been extensively documented, and are expected to be difficult to monitor. Increases in CO_2 leakage rates could result in concurrent increases in life cycle GHG emissions.
- **Pre-Existence of Infrastructure:** Some of the infrastructure needed within the boundary of this study, such as a pipeline network suitable for transferring F-T Jet Fuel to the blending facility, was assumed to be pre-existing. No GHG emissions penalty was included for this infrastructure.
- **Comparative Study Results:** The purpose of this study is to provide a comparative evaluation of alternative fuels against baseline 2005 conventional petroleum jet fuel production and use. Results provided for this scenario reflect life cycle emissions from alternative jet fuel production in comparison to that baseline. However, results from this scenario are not intended to provide absolute GHG emissions values; results from this study should be used with caution, when comparing to life cycle analyses having different baseline assumptions and study goals.

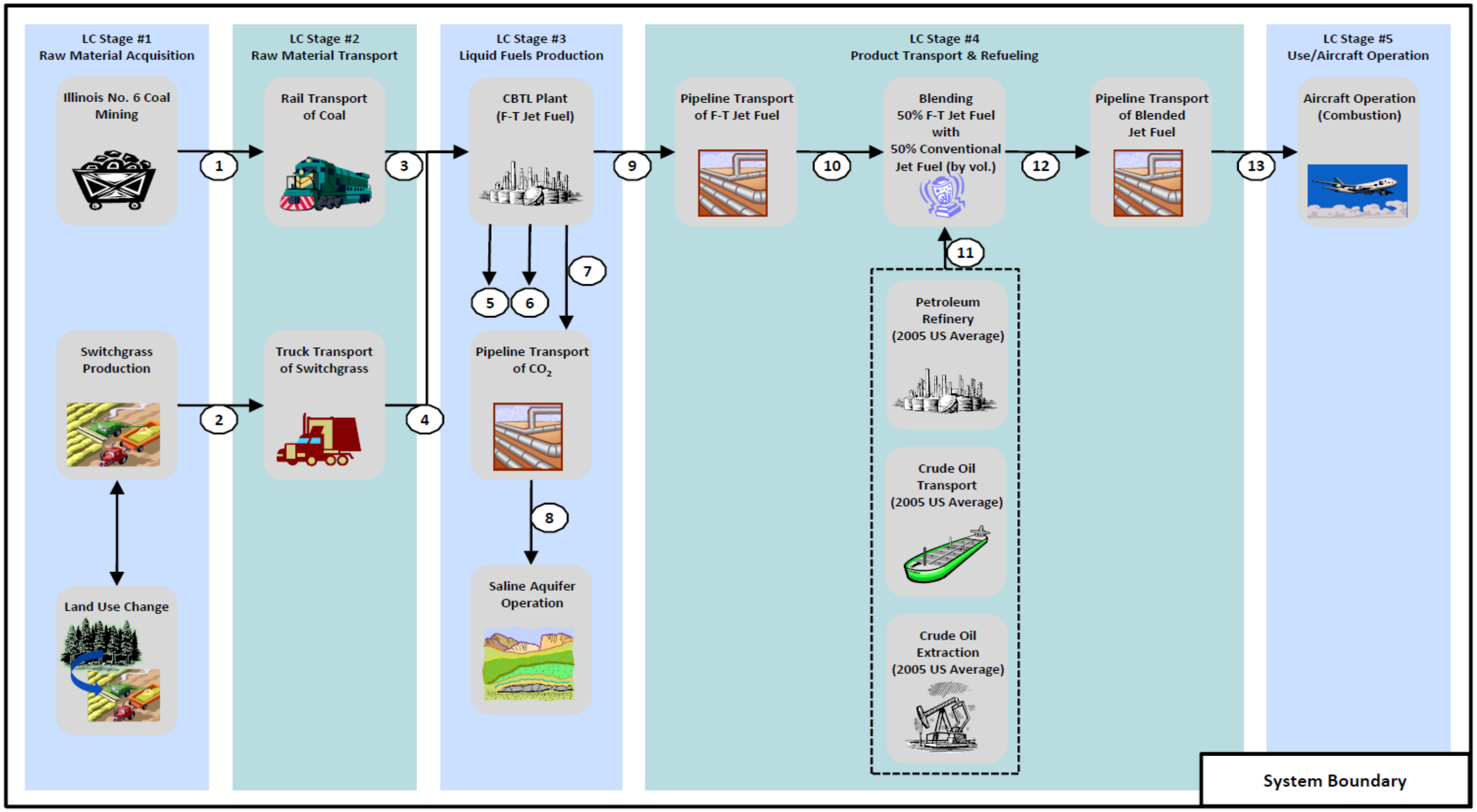
10.7 Scenario 7: 16 Percent Switchgrass, Iron F-T Catalyst, Saline Aquifer Sequestration

10.7.1 Scenario Overview

Scenario 7 was designed to evaluate F-T fuels derived from a combination of coal (84 percent by weight) and switchgrass (16 percent by weight) feedstocks, using saline aquifer sequestration. Like other scenarios, Scenario 7 assesses a 1:1 blend F-T and conventional jet fuel (US Average) over a period of 30 years. Illinois No. 6 sub-bituminous coal feedstock is shipped via train to a CBTL facility located in Northern Missouri. Regionally-grown and harvested switchgrass is shipped by diesel truck to the same facility, where it is dried and processed. The F-T process employed at the facility uses an iron catalyst without autothermal reforming, and with 91 percent flue gas carbon capture. The F-T process produces a combination of F-T jet fuel (52.9 percent by energy), F-T diesel (37.3 percent by energy), and F-T naphtha (9.83 percent by energy). Captured carbon dioxide is conveyed via a 100 mile pipeline to a saline aquifer carbon dioxide sequestration site where it is injected into the ground and eventually sequestered. Finally, the F-T jet fuel is conveyed via pipeline from the CBTL Facility to a separate blending facility, located at the Woods River Refinery in Illinois. Here it is blended with conventional jet fuel and shipped via pipeline to Chicago O'Hare Airport. Alternatively, the blended fuel may be shipped via a combination of pipeline and tanker truck to Chicago O'Hare and smaller regional airports. Scenario 7 is most closely related to Scenarios 2, 3, and 8, which also incorporate coal and biomass using an iron F-T catalyst. Table 164 provides an overview of key values for Scenario 7.

Table 164. Scenario 7 Overview

Item		Scenario Property		
Study Properties				
Functional Unit		1 MJ of Blended F-T Jet Fuel Consumed		
Blended F-T Jet Fuel		4,010 MJ/bbl		
F-T Jet Fuel		50 percent of final product (by volume)		
Conventional Jet Fuel (US Average)		50 percent of final product (by (volume)		
Temporal Boundary		30 years		
CBTL Facility Properties				
Plant Location		Northern Missouri		
Daily Production Capacity		30,000 bbl/d		
F-T Catalyst Type		Iron		
Autothermal Reforming		No		
Tail Gas Recycle		Yes		
Carbon Capture		91 percent in flue gas		
Optimized for Maximum F-T Jet Fuel Production		No		
Item	**Value**	**Units**	**Value**	**Units**
Energy Feedstock Inputs to CBTL Facility				
Coal, Illinois No. 6	11,354	short tons/day	84%	percent by mass
Biomass, Switchgrass	1,803	short tons/day	16%	percent by mass
Product Outputs from CBTL Plant				
CBTL Plant Liquid Product Output	30,000	bbl/d	100%	percent by energy
CBTL Plant F-T Jet Fuel Production	15,939	bbl/d	52.9%	percent by energy
CBTL Plant F-T-Diesel Fuel Production	10,769	bbl/d	37.3%	percent by energy
CBTL Plant F-T Naphtha Production	3,292	bbl/d	9.83%	percent by energy
Carbon Management Strategy: CO_2-Enhanced Oil Recovery (CO_2-EOR)				
Storage Location	N/A		N/A	N/A
Carbon Dioxide Sequestered	N/A	N/A	N/A	N/A
Crude Oil Production	N/A	N/A	N/A	N/A
Natural Gas Liquids Production	N/A	N/A	N/A	N/A
Carbon Management Strategy: Saline Aquifer				
Storage Location	Relative to CBTL Facility		100	miles from CBTL Facility
Carbon Dioxide Sequestered	15,889	short tons/day	99.5%	percent of CO_2 received
Product Transport to Airport				
F-T Jet Fuel Pipeline Transport to Wood River, Il Refinery	21,595	bbl/d	225	miles
Blended F-T Jet Fuel Pipeline Transport to Chicago O'Hare Airport	22,346	bbl/d	245	miles



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (dry)	52.9	g/MJ LHV	6	F-T Naphtha	2.04	g/MJ LHV	11	Conv. Jet Fuel	11.8	g/MJ LHV
2	Switchgrass (dry)	9.44	g/MJ LHV	7	Supercritical CO_2	83.7	g/MJ LHV	12	Blended Jet Fuel	22.8	g/MJ LHV
3	Illinois No. 6 Coal (dry)	52.9	g/MJ LHV	8	Supercritical CO_2	83.2	g/MJ LHV	13	Blended Jet Fuel	22.8	g/MJ LHV
4	Switchgrass (dry)	9.44	g/MJ LHV	9	F-T Jet Fuel	11.0	g/MJ LHV				
5	F-T Diesel	7.75	g/MJ LHV	10	F-T Jet Fuel	11.0	g/MJ LHV				

Figure 85. Scenario 7: System Boundary and Major Flows (g/MJ Jet Fuel Combusted, LHV)

10.7.2 Life Cycle GHG Results

Lifecycle GHG results are presented below for the deterministic analysis using the best estimate for each modeling parameter, probabilistic uncertainty analysis using the defined uncertainty ranges and probability distributions sampled approximately 2,000 times using a Monte Carlo simulation, and sensitivity analysis to determine the key modeling parameters within the life cycle with greatest influence on the results.

10.7.2.1 Deterministic Analysis Results

Allocated results are tabulated in terms of life cycle sub-categories in Table 165 for both energy allocation and system expansion/displacement allocation method. Total unallocated CO_2e emissions are also provided along with each allocated result to assist understanding of the effect of allocation on each final result. The unallocated results do not represent the life cycle GHG result for 1 MJ of blended F-T Jet Fuel consumed. Unallocated results represent the total GHG emissions released to the atmosphere to produce the suite of co-products produced within the study boundary.

Table 165. Scenario 7 Deterministic Analysis Results (Using IPCC 2007 GWP)

Life Cycle Stage Sub-categories	Unallocated CO_2e Emissions[1]		CO_2e Emissions Allocated by Energy		CO_2e Emissions Allocated by Displacement	
	g/MJ	%	g/MJ	%	g/MJ	%
LC Stage 1a: Illinois No. 6 Coal Acquisition	4.6	5.9%	2.5	3.2%	3.5	4.9%
LC Stage 2a: Coal Transport	0.8	1.0%	0.4	0.5%	0.6	0.8%
LC Stage 1b: Switchgrass Biomass Production	-15.4	-19.6%	-8.2	-10.4%	-19.1	-26.9%
LC Stage 1c: Direct Land Use	-0.4	-0.5%	-0.2	-0.3%	-0.4	-0.6%
LC Stage 1c: Indirect Land Use	1.4	1.8%	0.8	1.0%	1.1	1.6%
LC Stage 2b: Switchgrass Transport	0.4	0.5%	0.2	0.3%	0.3	0.4%
LC Stage 3a: CBTL Facility	8.1	10.3%	4.3	5.5%	6.1	8.6%
LC Stage 3b: Supercritical CO_2 Transport	0	0.0%	0	0.0%	0	0.0%
LC Stage 3c: Enhanced Oil Recovery (EOR)	0	0.0%	0	0.0%	0	0.0%
LC Stage 3d: Supercritical CO_2 Sequestration	0.5	0.6%	0.3	0.4%	0.4	0.6%
LC Stage 4: F-T Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 4: Conventional Jet Fuel Life Cycle	6.9	8.8%	6.9	8.8%	6.9	9.7%
LC Stage 4: Blended Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 5: Jet Fuel Use	71.4	90.8%	71.4	90.8%	71.4	100.7%
Life Cycle Total:	78.6	100.0%	78.6	100.0%	70.9	100.0%

1. Unallocated results represent all co-products produced within the system boundary therefore do not represent the life cycle GHG results for 1 MJ of blended F-T jet fuel consumed. The unallocated results are presented only to illustrate the effect of allocation.

The deterministic analysis results in a 10 percent reduction in life cycle GHG emissions in comparison to a conventional jet fuel baseline of 87.4 g CO_2e/MJ jet fuel combusted, LHV when allocated by energy. Allocation of the co-products using the displacement method results a 19 percent reduction in the life cycle GHG profile compared to conventional jet fuel baseline. Thus the deterministic results of this study show that the life cycle GHG profile for Scenario 7 is 19 percent to 10 percent below the conventional jet fuel baseline.

Results by life cycle stage contribution show that fuel combustion (use phase) accounts for the majority of life cycle GHG emissions for both energy allocation (91 percent of total life cycle

emissions) and displacement (101 percent of total lifecycle emissions) respectively. Note that uptake of carbon by switchgrass is accounted for as a negative CO_2e emission, and therefore emission of over 100 percent of life cycle emissions is possible for jet fuel use. Excluding the use phase, the upstream life cycle stage with the next highest life cycle GHG contribution does not differ by the method of co-product allocation. The next largest contributor for both allocation methods is the conventional jet fuel production life cycle followed by CBTL operation. Interestingly, the CBTL facility contributes only 6 percent to 9 percent to the total life cycle GHG profile, depending on method of allocation.

10.7.2.2 Probabilistic Uncertainty Analysis Results

Table 166 presents summary statistics for probabilistic CO_2e emissions for Scenario 7 (16 percent switchgrass, iron F-T catalyst, normal product slate, and sequestration) along with the "best estimate" (i.e., the deterministic result). Figure 86 presents the probabilistic results in a "box and whisker" plot. Table 166 has the same structure as Table 141, while Figure 86 has the same structure as Figure 66**.**

Scenario 7 provides a convenient comparison point to Scenario 2: Scenario 7 includes CO_2 sequestration as a carbon management strategy, rather than CO_2 EOR. As shown, median CO_2e emissions values are substantially below conventional jet fuel emissions for both energy and displacement allocation. Median emissions under energy allocation are lower by 8.8 g CO_2e/MJ LHV, while median emissions under displacement allocation are lower by 16.4 g CO_2e/MJ LHV. For both energy and displacement allocation, the entire distribution of CO_2e emissions is below the conventional jet fuel value. In comparison to Scenario 2, Scenario 7 indicates that CO_2 sequestration is more effective at lowering lifecycle CO_2 emissions than CO_2-EOR, as relevant to this study.

Table 166. Scenario 7 Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

Quantity	CO_2e Emissions Allocated by Energy (g CO_2e/MJ LHV)	CO_2e Emissions Allocated by Displacement (g CO_2e/MJ LHV)	Combined CO_2e Emissions (g CO_2e/MJ LHV)
Minimum	77.1	67.9	67.9
25th Percentile	78.3	70.2	70.9
Median	78.6	71.0	72.8
75th Percentile	79.0	71.7	78.6
Maximum	80.5	74.7	80.2
Best Estimate	78.6	70.9	74.8
Conventional Jet Fuel	87.4	87.4	87.4

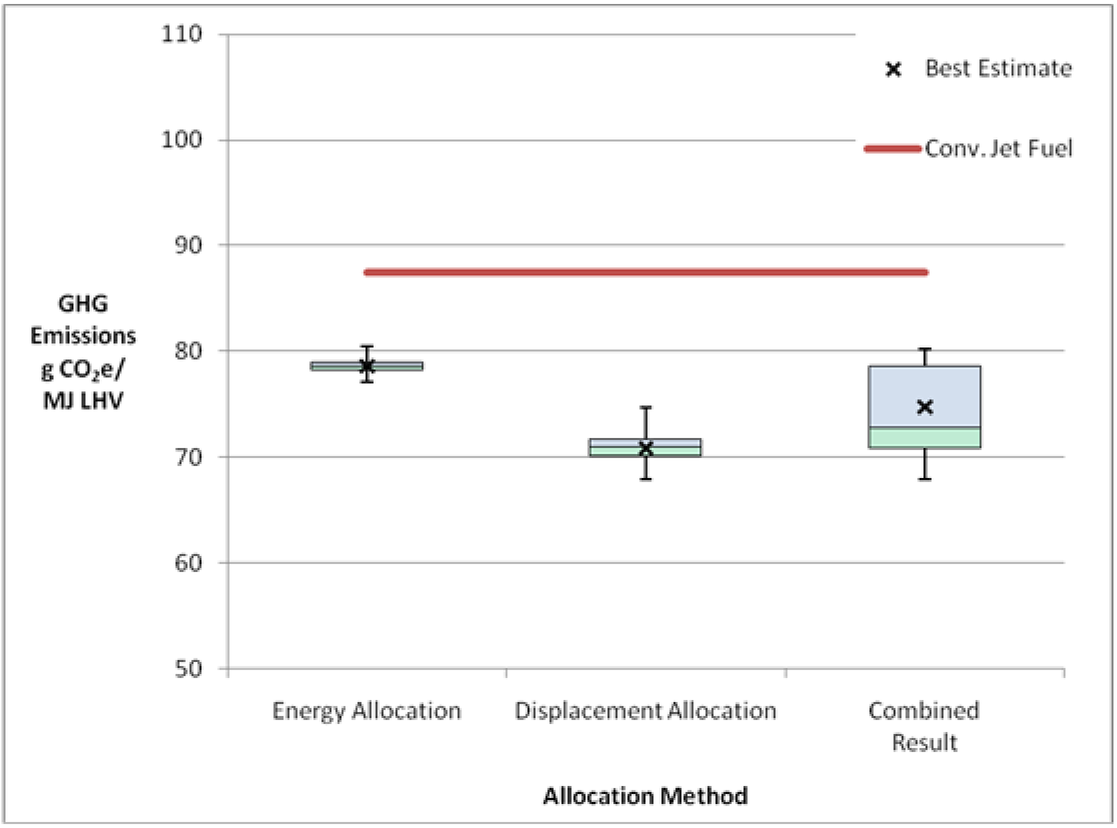


Figure 86. Scenario 7 Box and Whisker Plot of Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

10.7.2.3 Sensitivity Analysis Results

Sensitivity analysis results were calculated for both co-product allocation procedures (energy allocation and displacement method) by adjusting each modeling parameter independently between the minimum and maximum values to determine the effect on the final life cycle GHG result. The 24 modeling parameters with the greatest effect on the results was determined and ranked from highest to lowest based on their absolute difference. The results are reported in both tabular and graphical form in Table 167 and Figure 87 for the energy allocation results and Table 168 and Figure 88 for the displacement method results. All results are reported based on the IPCC 2007 global warming potentials.

Table 167. Scenario 7 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	81.6	82.1	0.562
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.69	82	81.7	0.278
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	82	81.7	0.266
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	81.8	82	0.213
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	81.8	82	0.193
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	81.8	81.9	0.171
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air_3c	kg/kg	0.005	0	0.01	81.8	81.9	0.139
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	81.8	82	0.117
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	81.9	81.8	0.11
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	81.8	81.9	0.106
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	81.8	81.9	0.0948
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	81.8	81.9	0.0913
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	81.8	81.9	0.087
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	81.8	81.9	0.0635
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	81.8	81.9	0.0493

Table 167. Scenario 7 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) ***(Cont'd)***

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	81.9	81.9	0.0346
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	81.8	81.9	0.0253
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	81.9	81.9	0.00979
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	81.9	81.9	0.00596
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	81.9	81.9	0.00474
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	81.9	81.9	0.00438
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	81.9	81.9	0.0042
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	100	90	110	81.9	81.9	0.00331
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	81.9	81.9	0.00294

Table 168. Scenario 7 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	78.4	80.3	1.92
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.62	7.54	7.69	80.1	78.4	1.68
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	80.1	78.5	1.61
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	79.7	78.4	1.3
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	78.7	79.8	1.16
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	78.7	79.8	1.03
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air_3c	kg/kg	0.005	0	0.01	78.8	79.7	0.843
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	79	79.6	0.573
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	79	79.5	0.562
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	79	79.5	0.552
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	79.1	79.5	0.384
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	79.1	79.4	0.328
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	79.1	79.4	0.298
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	79.2	79.3	0.153
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	79.2	79.4	0.117

Table 168. Scenario 7 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) ***(Cont'd)***

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	79.2	79.3	0.106
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	79.2	79.3	0.0585
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	79.3	79.3	0.036
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	79.3	79.3	0.0346
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	79.3	79.3	0.0283
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	79.2	79.3	0.0265
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	79.3	79.3	0.0254
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	100	90	110	79.3	79.3	0.02
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	79.3	79.3	0.0178

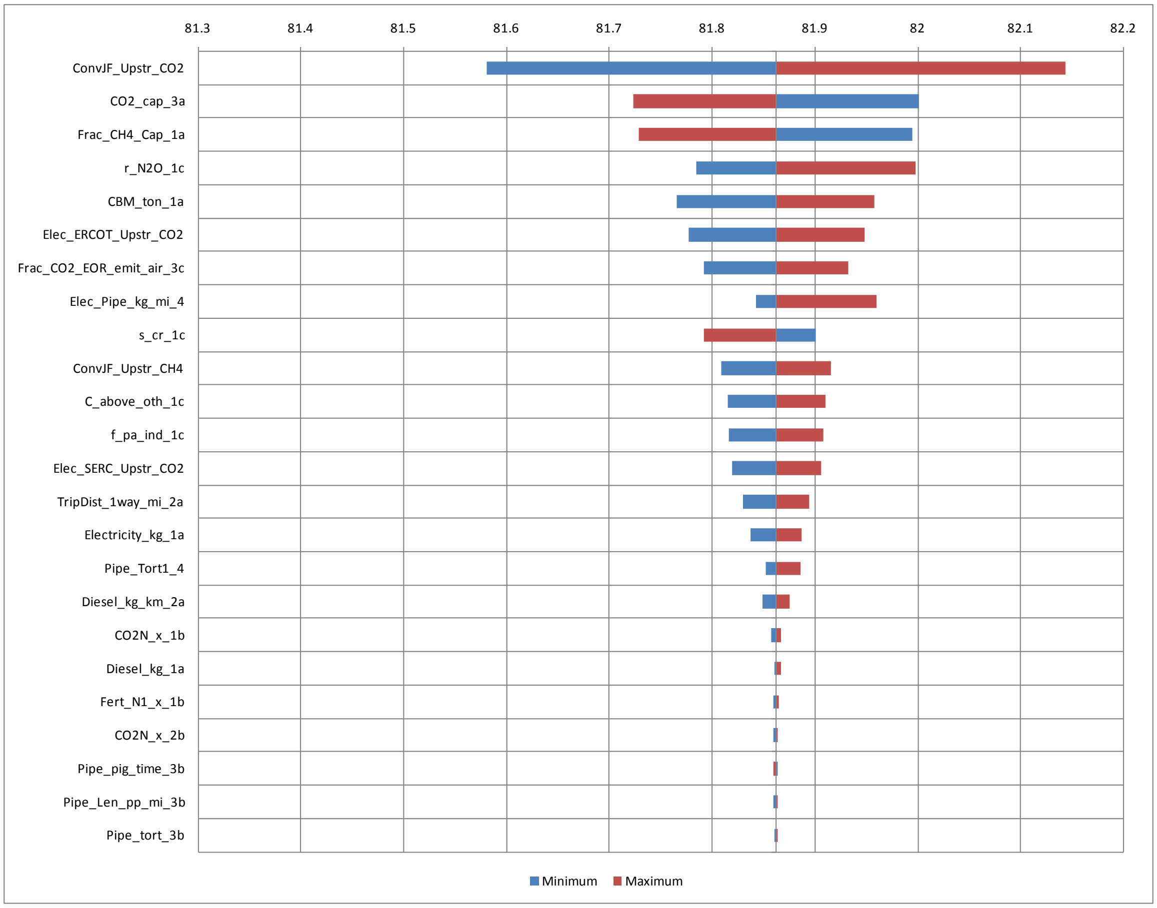


Figure 87. Scenario 7 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

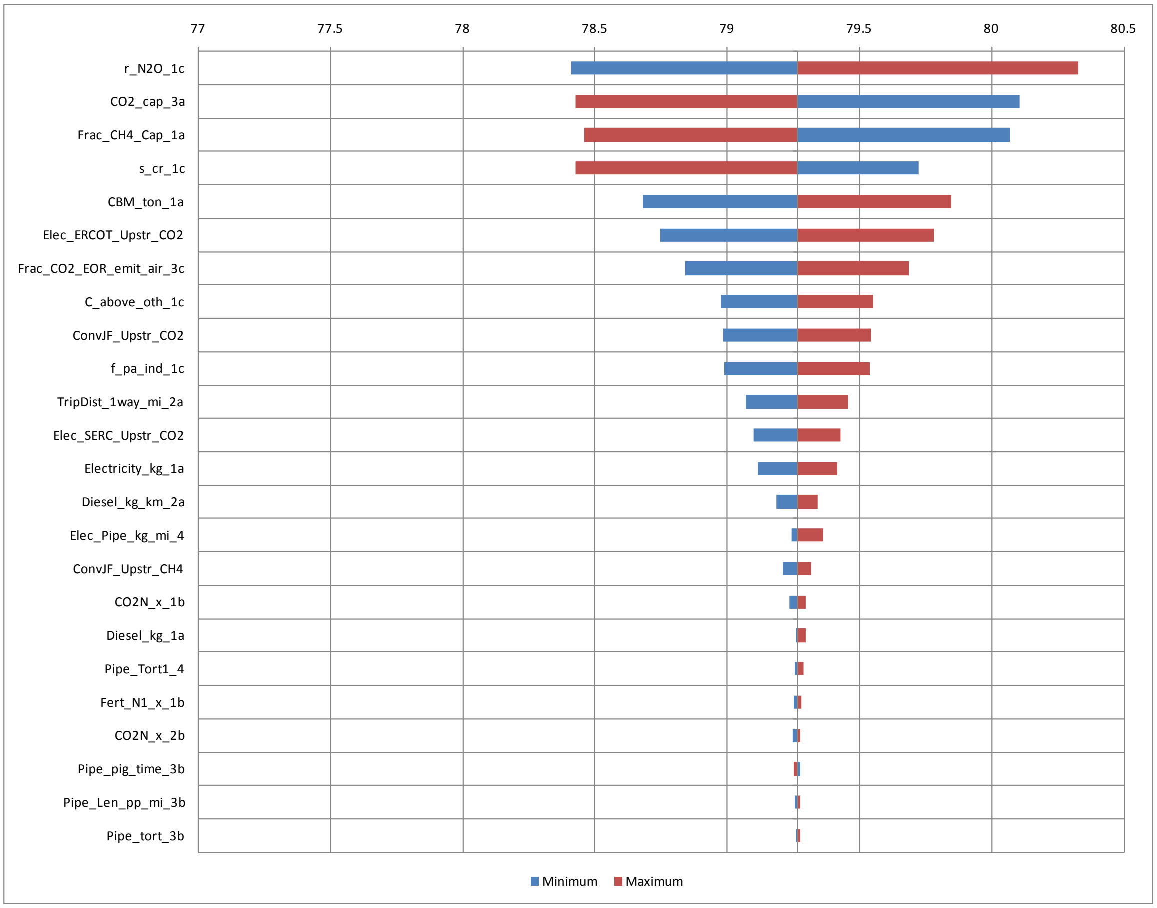


Figure 88. Scenario 7 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

10.7.3 Data Limitations

In terms of broader study limitations, the model boundaries and modeling choices contained in this scenario inform the following study limitations, which should be considered when interpreting final results and conclusions generated from this study:

- **Mine and Mine Methane Emissions:** This scenario presumes that Illinois No. 6 sub-bituminous coal from an underground longwall mine would be used, having an average methane emission rate of 150 scf CH_4/ton with 40 percent capture. Use of an alternative coal type, mine type, methane emission rate, or methane capture rate could increase or decrease mine and mine methane related GHG emissions.
- **Biomass Production:** This scenario presumes that farmed switchgrass would be used as the sole source of biomass. However, alternative sources of biomass could also have been chosen, such as farmed short rotation woody crops or corn stover, or biomass waste streams such as agricultural wastes or logging wastes. The use of alternative farming practices, crop requirements, and/or biomass source could increase or reduce life cycle GHG emissions.

- **Biomass Yields:** This scenario presumes that switchgrass production would yield 4.7 dry tons per acre per year of biomass. However, switchgrass yields reported in the literature are highly variable, in part reflecting farming practices and regional conditions. Higher or lower switchgrass yield values could substantially decrease or increase life cycle land use, respectively.
- **Biomass Transport:** This scenario presumes a 50 mile switchgrass production radius. The intensity of biomass transport emissions is expected to increase with increases in production radius. Therefore, substantial increases in the biomass production radius for this study could result in concurrent increases in transportation related GHG emissions, as well as increases in cost, which under some cases could render a longer distance biomass collection scheme infeasible.
- **CBTL Facility Carbon Capture Rate:** The rate of carbon capture at the F-T facility used for this scenario is 91 percent, which is expected to be a conservative estimate of actual carbon capture rates. However, carbon capture facilities have not been widely implemented at the commercial scale. Therefore, a higher or lower carbon capture rate may apply to some future studies. Increases or decreases in this rate would result in concurrent increases or decreases in life cycle GHG emissions.
- **CBTL Facility Modeling Scenarios:** In order to model the F-T facility, output from a separate ASPEN model was incorporated into the life cycle model used for this study. As a result, the F-T facility model included in this study is static: the workings of the F-T facility cannot be updated or altered to evaluate different F-T facility parameters and setups, without performing substantial additional analysis. The F-T facility results from this study represent specific assumptions, as documented in **Section 6**, and are not necessarily representative of all potential F-T Facility designs.
- **Saline Sequestration Leakage Rates:** This scenario incorporates CO_2 leakage rates of less than one percent. However, actual leakage rates have not been extensively documented, and are expected to be difficult to monitor. Increases in CO_2 leakage rates could result in concurrent increases in life cycle GHG emissions.
- **Pre-Existence of Infrastructure:** Some of the infrastructure needed within the boundary of this study, such as a pipeline network suitable for transferring F-T Jet Fuel to the blending facility, was assumed to be pre-existing. No GHG emissions penalty was included for this infrastructure.
- **Comparative Study Results:** The purpose of this study is to provide a comparative evaluation of alternative fuels against baseline 2005 conventional petroleum jet fuel production and use. Results provided for this scenario reflect life cycle emissions from alternative jet fuel production in comparison to that baseline. However, results from this scenario are not intended to provide absolute GHG emissions values; results from this study should be used with caution, when comparing to life cycle analyses having different baseline assumptions and study goals.

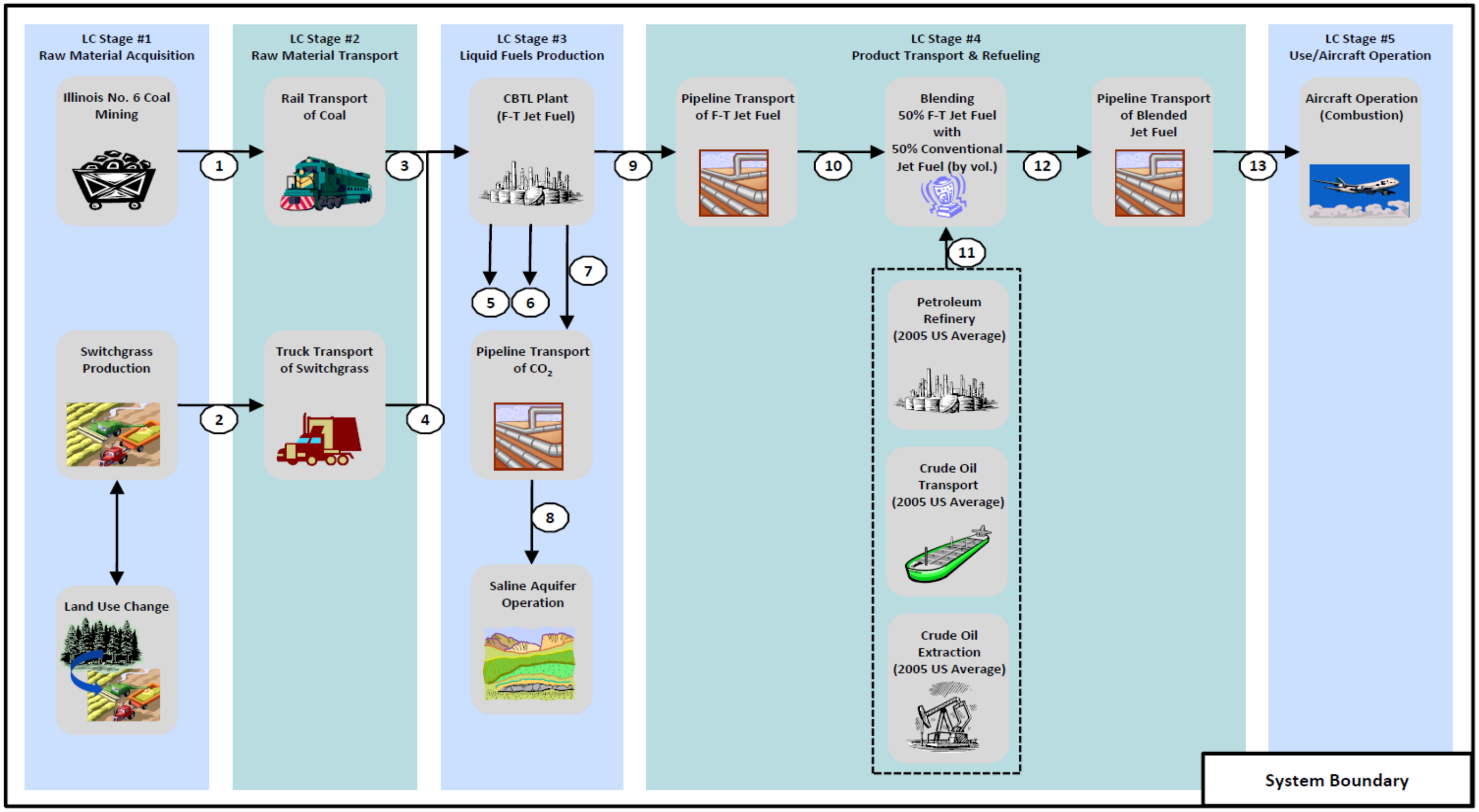
10.8 Scenario 8: 31 Percent Switchgrass, Iron F-T Catalyst, Saline Aquifer Sequestration

10.8.1 Scenario Overview

Scenario 8 was designed to evaluate F-T fuels derived from a combination of coal (69 percent by weight) and switchgrass (31 percent by weight) feedstocks. Like other scenarios, Scenario 8 assesses a 1:1 blend F-T and conventional jet fuel (US Average) over a period of 30 years. Illinois No. 6 sub-bituminous coal feedstock is shipped via train to a CBTL facility located in Northern Missouri. Regionally-grown and harvested switchgrass is shipped by diesel truck to the same facility, where it is dried and processed. The F-T process employed at the facility uses an iron catalyst without autothermal reforming, and with 91 percent flue gas carbon capture. The F-T process produces a combination of F-T jet fuel (52.9 percent by energy), F-T diesel (37.3 percent by energy), and F-T naphtha (9.83 percent by energy). Captured carbon dioxide is conveyed via a 100 mile pipeline to a saline aquifer carbon dioxide sequestration site where it is injected into the ground and eventually sequestered. Finally, the F-T jet fuel is conveyed via pipeline from the CBTL Facility to a separate blending facility, located at the Woods River Refinery in Illinois. Here it is blended with conventional jet fuel and shipped via pipeline to Chicago O'Hare Airport. Alternatively, the blended fuel may be shipped via a combination of pipeline and tanker truck to Chicago O'Hare and smaller regional airports. Scenario 8 is an analogue to Scenario 7, except that Scenario 8 incorporates a higher proportion of switchgrass than Scenario 7. Scenario 8 is also closely related to Scenarios 2 and 3, which also incorporate coal and biomass using an iron F-T catalyst. Table 169 provides an overview of key values for Scenario 8.

Table 169. Scenario 8 Overview

Item		Scenario Property		
Study Properties				
Functional Unit		1 MJ of Blended F-T Jet Fuel Consumed		
Blended F-T Jet Fuel		4,010 MJ/bbl		
F-T Jet Fuel		50 percent of final product (by volume)		
Conventional Jet Fuel (US Average)		50 percent of final product (by (volume)		
Temporal Boundary		30 years		
CBTL Facility Properties				
Plant Location		Northern Missouri		
Daily Production Capacity		30,000 bbl/d		
F-T Catalyst Type		Iron		
Autothermal Reforming		No		
Tail Gas Recycle		Yes		
Carbon Capture		91 percent in flue gas		
Optimized for Maximum F-T Jet Fuel Production		No		
Item	**Value**	**Units**	**Value**	**Units**
Energy Feedstock Inputs to CBTL Facility				
Coal, Illinois No. 6	9,891	short tons/day	69%	percent by mass
Biomass, Switchgrass	3,816	short tons/day	31%	percent by mass
Product Outputs from CBTL Plant				
CBTL Plant Liquid Product Output	30,000	bbl/d	100%	percent by energy
CBTL Plant F-T Jet Fuel Production	15,939	bbl/d	52.9%	percent by energy
CBTL Plant F-T-Diesel Fuel Production	10,769	bbl/d	37.3%	percent by energy
CBTL Plant F-T Naphtha Production	3,292	bbl/d	9.83%	percent by energy
Carbon Management Strategy: CO_2-Enhanced Oil Recovery (CO_2-EOR)				
Storage Location	N/A		N/A	N/A
Carbon Dioxide Sequestered	N/A	N/A	N/A	N/A
Crude Oil Production	N/A	N/A	N/A	N/A
Natural Gas Liquids Production	N/A	N/A	N/A	N/A
Carbon Management Strategy: Saline Aquifer				
Storage Location	Relative to CBTL Facility		100	miles from CBTL Facility
Carbon Dioxide Sequestered	15,885	short tons/day	99.5%	percent of CO_2 received
Product Transport to Airport				
F-T Jet Fuel Pipeline Transport to Wood River, Il Refinery	21,595	bbl/d	225	miles
Blended F-T Jet Fuel Pipeline Transport to Chicago O'Hare Airport	22,346	bbl/d	245	miles



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (dry)	46.1	g/MJ LHV	6	F-T Naphtha	2.04	g/MJ LHV	11	Conv. Jet Fuel	11.8	g/MJ LHV
2	Switchgrass (dry)	20.0	g/MJ LHV	7	Supercritical CO_2	83.7	g/MJ LHV	12	Blended Jet Fuel	22.8	g/MJ LHV
3	Illinois No. 6 Coal (dry)	46.1	g/MJ LHV	8	Supercritical CO_2	83.2	g/MJ LHV	13	Blended Jet Fuel	22.8	g/MJ LHV
4	Switchgrass (dry)	20.0	g/MJ LHV	9	F-T Jet Fuel	11.0	g/MJ LHV				
5	F-T Diesel	7.75	g/MJ LHV	10	F-T Jet Fuel	11.0	g/MJ LHV				

Figure 89. Scenario 8: System Boundary and Major Flows (g/MJ Jet Fuel Combusted, LHV)

10.8.2 Life Cycle GHG Results

Lifecycle GHG results are presented below for the deterministic analysis using the best estimate for each modeling parameter, probabilistic uncertainty analysis using the defined uncertainty ranges and probability distributions sampled approximately 2,000 times using a Monte Carlo simulation, and sensitivity analysis to determine the key modeling parameters within the life cycle with greatest influence on the results.

10.8.2.1 Deterministic Analysis Results

Allocated results are tabulated in terms of life cycle sub-categories in Table 170 for both energy allocation and system expansion/displacement allocation method. Total unallocated CO_2e emissions are also provided along with each allocated result to assist understanding of the effect of allocation on each final result. The unallocated results do not represent the life cycle GHG result for 1 MJ of blended F-T Jet Fuel consumed. Unallocated results represent the total GHG emissions released to the atmosphere to produce the suite of co-products produced within the study boundary.

Table 170. Scenario 8 Deterministic Analysis Results (Using IPCC 2007 GWP)

Life Cycle Stage Sub-categories	Unallocated CO_2e Emissions[1]		CO_2e Emissions Allocated by Energy		CO_2e Emissions Allocated by Displacement	
	g/MJ	%	g/MJ	%	g/MJ	%
LC Stage 1a: Illinois No. 6 Coal Acquisition	4	6.3%	2.1	3.0%	3.4	6.2%
LC Stage 2a: Coal Transport	0.7	1.1%	0.4	0.6%	0.6	1.1%
LC Stage 1b: Switchgrass Biomass Production	-32.6	-51.7%	-17.3	-24.6%	-37.5	-67.9%
LC Stage 1c: Direct Land Use	-0.7	-1.1%	-0.4	-0.6%	-0.9	-1.6%
LC Stage 1c: Indirect Land Use	3	4.8%	1.6	2.3%	2.6	4.7%
LC Stage 2b: Switchgrass Transport	0.8	1.3%	0.4	0.6%	0.6	1.1%
LC Stage 3a: CBTL Facility	8.7	13.8%	4.6	6.5%	7.4	13.4%
LC Stage 3b: Supercritical CO_2 Transport	0	0.0%	0	0.0%	0	0.0%
LC Stage 3c: Enhanced Oil Recovery (EOR)	0	0.0%	0	0.0%	0	0.0%
LC Stage 3d: Supercritical CO_2 Sequestration	0.5	0.8%	0.3	0.4%	0.4	0.7%
LC Stage 4: F-T Jet Fuel Transport	0.1	0.2%	0.1	0.1%	0.1	0.2%
LC Stage 4: Conventional Jet Fuel Life Cycle	6.9	11.0%	6.9	9.8%	6.9	12.5%
LC Stage 4: Blended Jet Fuel Transport	0.1	0.2%	0.1	0.1%	0.1	0.2%
LC Stage 5: Jet Fuel Use	71.4	113.3%	71.4	101.6%	71.4	129.3%
Life Cycle Total:	63	100.0%	70.3	100.0%	55.2	100.0%

1. Unallocated results represent all co-products produced within the system boundary therefore do not represent the life cycle GHG results for 1 MJ of blended F-T jet fuel consumed. The unallocated results are presented only to illustrate the effect of allocation.

The deterministic analysis results in a 20 percent reduction in life cycle GHG emissions in comparison to a conventional jet fuel baseline of 87.4 g CO_2e/MJ jet fuel combusted, LHV when allocated by energy. Allocation of the co-products using the displacement method results a 37 percent reduction in the life cycle GHG profile compared to conventional jet fuel baseline. Thus the deterministic results of this study show that the life cycle GHG profile for Scenario 8 is 37 percent to 20 percent below the conventional jet fuel baseline.

Results by life cycle stage contribution show that fuel combustion (use phase) accounts for the majority of life cycle GHG emissions for both energy allocation (102 percent of total life cycle

emissions) and displacement (129 percent of total lifecycle emissions) respectively. Note that uptake of carbon by switchgrass is accounted for as a negative CO_2e emission, and therefore emission values that are greater 100 percent of life cycle emissions is possible for jet fuel use. Excluding the use phase, the upstream life cycle stage with the next highest life cycle GHG contribution differs by the method of co-product allocation. The next largest contributor for energy allocation is the conventional jet fuel production life cycle followed by CBTL operation; for displacement allocation, the trend is reversed. The CBTL facility contributes approximately 7 percent to 13 percent to the total life cycle GHG profile, depending on method of allocation.

10.8.2.2 Probabilistic Uncertainty Analysis Results

Table 171 presents summary statistics for probabilistic CO_2e emissions for Scenario 8 (31 percent switchgrass, iron catalyst, normal product slate, and sequestration) along with the "best estimate" (i.e., the deterministic result). Figure 90 presents the probabilistic results in a "box and whisker" plot. Table 171 has the same structure as Table 141, while Figure 90 has the same structure as Figure 66**.**

Scenario 8 provides a convenient comparison point to Scenario 3: Scenario 8 includes CO_2 sequestration as a carbon management strategy, rather than CO_2 EOR. As shown, median CO_2e emissions values are well below conventional jet fuel emissions for both energy and displacement allocation. Median emissions under energy allocation are lower by 17.0 g CO_2e/MJ LHV, while median emissions under displacement allocation are lower than conventional jet fuel emissions by 32.0 g CO_2e/MJ LHV. For both energy and displacement allocation, the entire distribution of CO_2e emissions is substantially below the conventional jet fuel value. In comparison to Scenario 3, Scenario 8 indicates that CO_2 sequestration is more effective than CO_2-EOR at lowering lifecycle CO_2 emissions, as relevant to this study.

Table 171. Scenario 8 Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

Quantity	CO_2e Emissions Allocated by Energy (g CO_2e/MJ LHV)	CO_2e Emissions Allocated by Displacement (g CO_2e/MJ LHV)	Combined CO_2e Emissions (g CO_2e/MJ LHV)
Minimum	68.2	51.0	51.0
25^{th} Percentile	70.0	54.4	55.4
Median	70.4	55.4	68.8
75^{th} Percentile	70.9	56.3	70.4
Maximum	73.1	60.6	73.1
Best Estimate	70.3	55.2	62.8
Conventional Jet Fuel	87.4	87.4	87.4

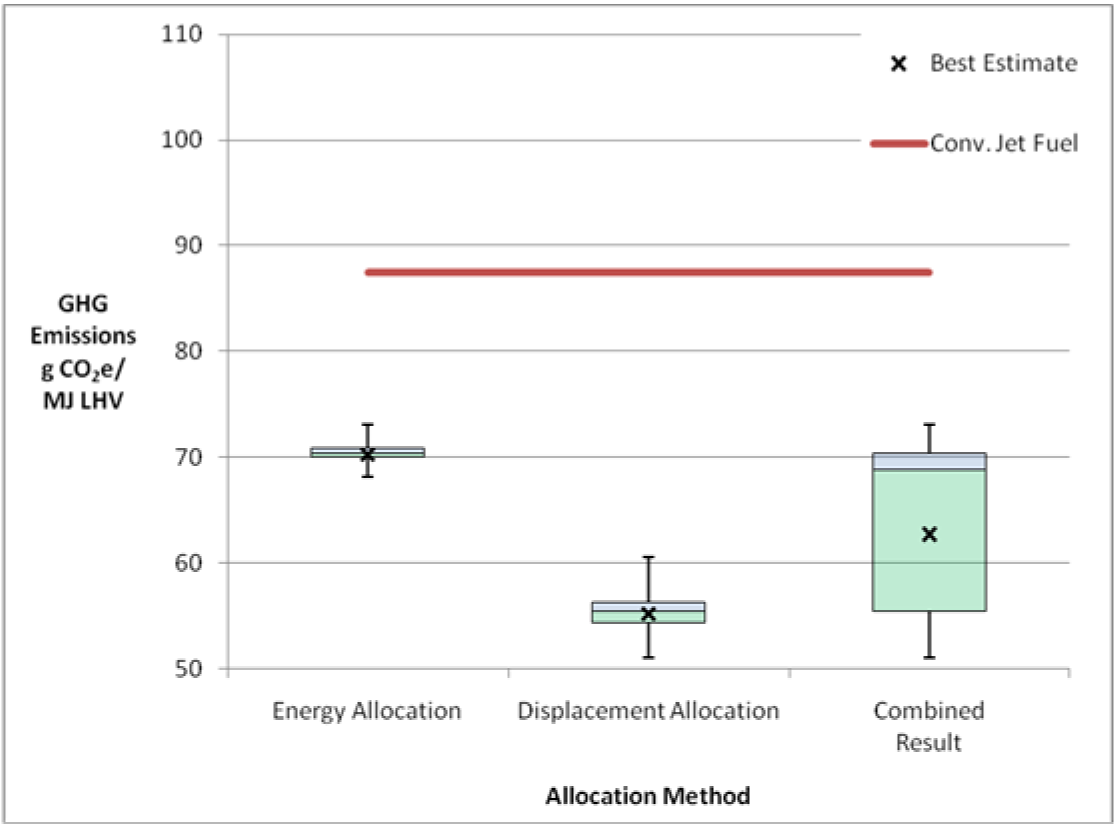


Figure 90. Scenario 8 Box and Whisker Plot of Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

10.8.2.3 Sensitivity Analysis Results

Sensitivity analysis results were calculated for both co-product allocation procedures (energy allocation and displacement method) by adjusting each modeling parameter independently between the minimum and maximum values to determine the effect on the final life cycle GHG result. The 24 modeling parameters with the greatest effect on the results was determined and ranked from highest to lowest based on their absolute difference. The results are reported in both tabular and graphical form in Table 172 and Figure 91 for the energy allocation results and Table 173 and Figure 92 for the displacement method results. All results are reported based on the IPCC 2007 global warming potentials.

Table 172. Scenario 8 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	80.8	79.9	0.932
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.06	6.99	7.13	80.8	79.9	0.9
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	80.1	80.9	0.745
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	80	80.7	0.674
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	80.1	80.7	0.562
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS_3d	tonne/tonne	0.005	0	0.01	80.2	80.6	0.452
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	80.5	80.1	0.383
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	80.2	80.5	0.331
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	80.2	80.5	0.319
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	80.3	80.5	0.222
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	80.3	80.5	0.206
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	80.3	80.5	0.173
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	80.4	80.5	0.117
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	80.4	80.3	0.114

Table 172. Scenario 8 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	80.3	80.4	0.106
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	775	698	853	80.3	80.4	0.0899
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	80.3	80.4	0.0886
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	80.4	80.4	0.0799
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	80.4	80.4	0.0346
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	80.4	80.4	0.0342
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	80.4	80.4	0.0208
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	80.4	80.4	0.0166
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	80.4	80.4	0.0153
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	80.4	80.4	0

Table 173. Scenario 8 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	76.5	74.9	1.61
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	75	76.6	1.59
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.06	6.99	7.13	76.5	74.9	1.55
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	75.1	76.3	1.16
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	76	75.1	0.973
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS _3d	tonne/tonne	0.005	0	0.01	75.3	76.1	0.781
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	75.4	76	0.572
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	75.4	76	0.562
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	75.4	76	0.551
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	75.5	75.9	0.383
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_C O2	kg CO_2/kWh	0.762	0.686	0.838	75.5	75.9	0.328
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	75.6	75.9	0.298
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	75.8	75.6	0.198
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	775	698	853	75.6	75.8	0.155
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	75.6	75.8	0.153

Table 173. Scenario 8 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	75.7	75.8	0.138
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	75.7	75.8	0.117
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	75.7	75.8	0.106
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	75.7	75.7	0.0585
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	75.7	75.7	0.036
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	75.7	75.7	0.0346
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	75.7	75.7	0.0283
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	75.7	75.7	0.0264
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	75.7	75.7	0

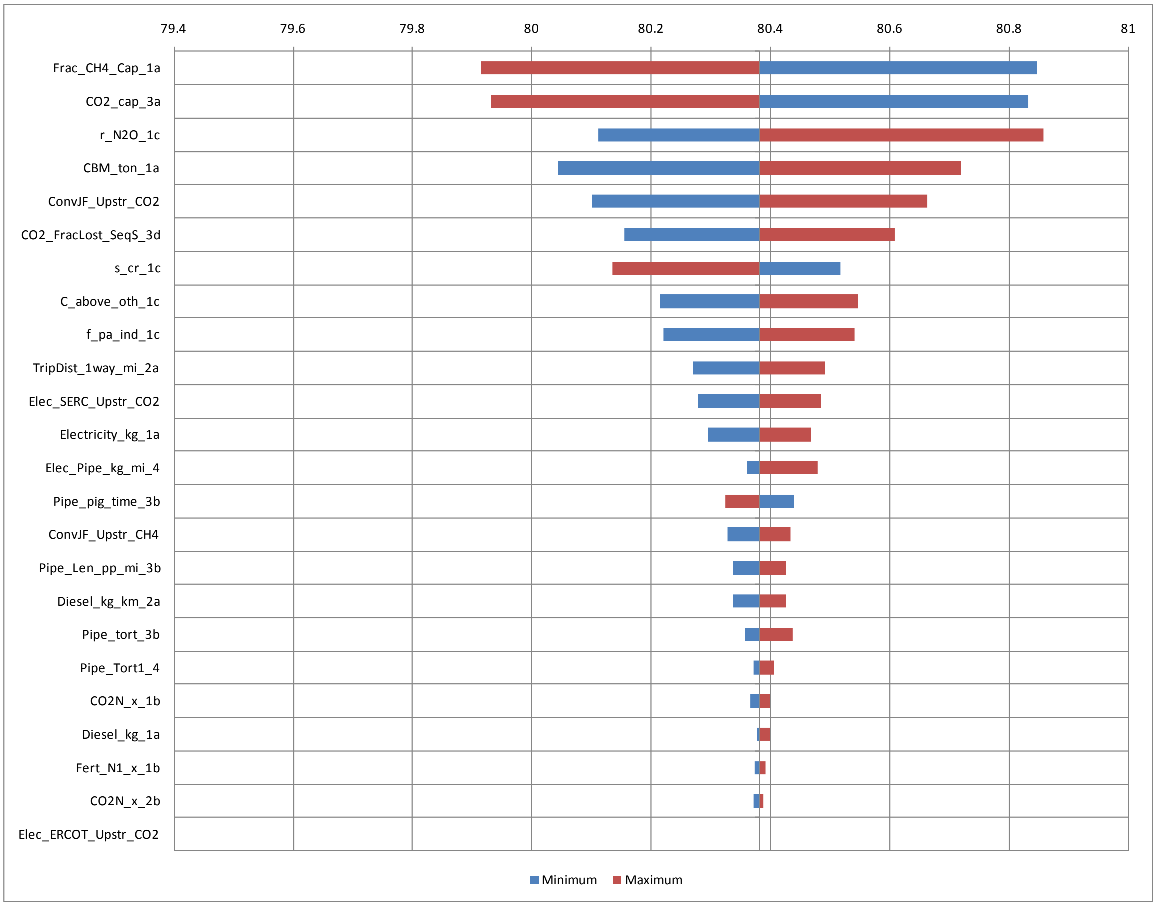


Figure 91. Scenario 8 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

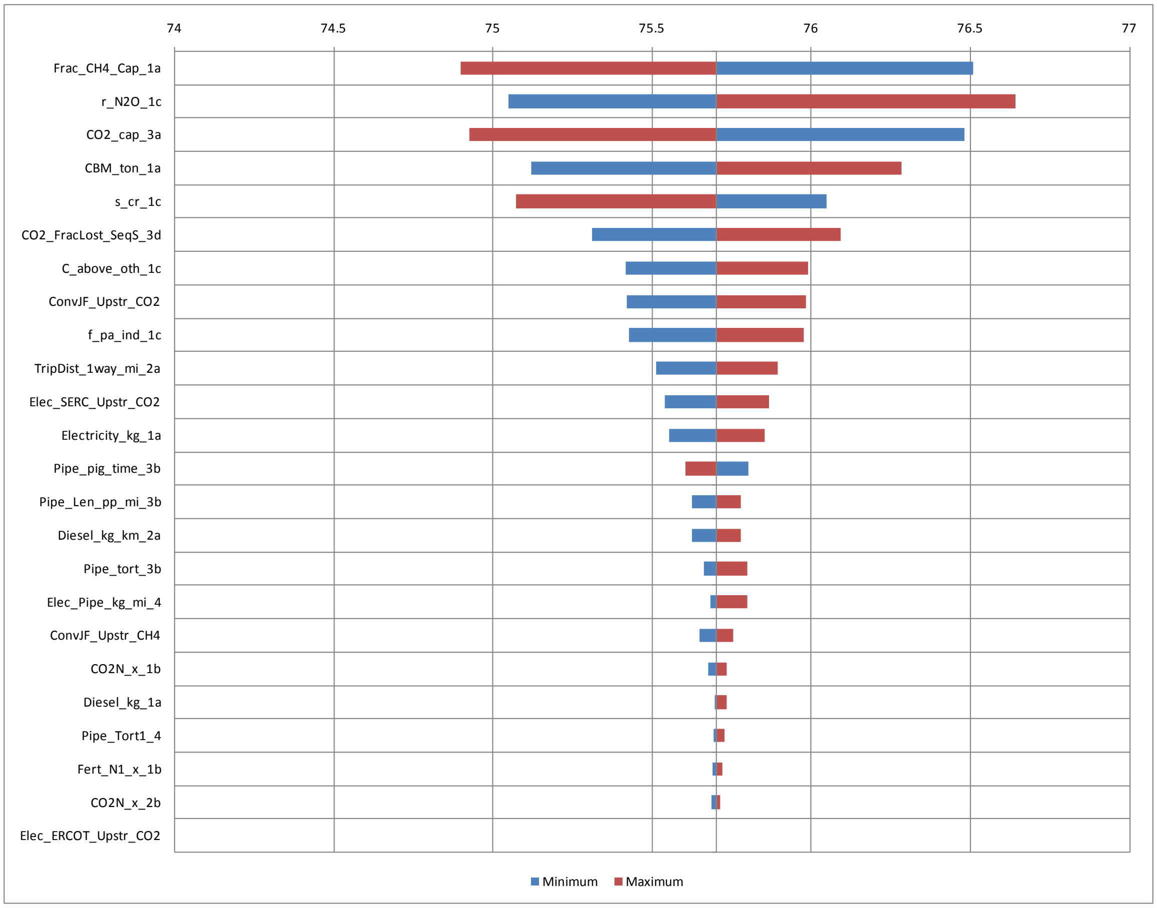


Figure 92. Scenario 8 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

10.8.3 Data Limitations

In terms of broader study limitations, the model boundaries and modeling choices contained in this scenario inform the following study limitations, which should be considered when interpreting final results and conclusions generated from this study:

- **Mine and Mine Methane Emissions:** This scenario presumes that Illinois No. 6 sub-bituminous coal from an underground longwall mine would be used, having an average methane emission rate of 150 scf CH_4/ton with 40 percent capture. Use of an alternative coal type, mine type, methane emission rate, or methane capture rate could increase or decrease mine and mine methane related GHG emissions.
- **Biomass Production:** This scenario presumes that farmed switchgrass would be used as the sole source of biomass. However, alternative sources of biomass could also have been chosen, such as farmed short rotation woody crops or corn stover, or biomass waste streams such as agricultural wastes or logging wastes. The use of alternative farming practices, crop requirements, and/or biomass source could increase or reduce life cycle GHG emissions.

- **Biomass Yields:** This scenario presumes that switchgrass production would yield 4.7 dry tons per acre per year of biomass. However, switchgrass yields reported in the literature are highly variable, in part reflecting farming practices and regional conditions. Higher or lower switchgrass yield values could substantially decrease or increase life cycle land use, respectively.
- **Biomass Transport:** This scenario presumes a 50 mile switchgrass production radius. The intensity of biomass transport emissions is expected to increase with increases in production radius. Therefore, substantial increases in the biomass production radius for this study could result in concurrent increases in transportation related GHG emissions, as well as increases in cost, which under some cases could render a longer distance biomass collection scheme infeasible.
- **CBTL Facility Carbon Capture Rate:** The rate of carbon capture at the F-T facility used for this scenario is 91 percent, which is expected to be a conservative estimate of actual carbon capture rates. However, carbon capture facilities have not been widely implemented at the commercial scale. Therefore, a higher or lower carbon capture rate may apply to some future studies. Increases or decreases in this rate would result in concurrent increases or decreases in life cycle GHG emissions.
- **CBTL Facility Modeling Scenarios:** In order to model the F-T facility, output from a separate ASPEN model was incorporated into the life cycle model used for this study. As a result, the F-T facility model included in this study is static: the workings of the F-T facility cannot be updated or altered to evaluate different F-T facility parameters and setups, without performing substantial additional analysis. The F-T facility results from this study represent specific assumptions, as documented in **Section 6**, and are not necessarily representative of all potential F-T Facility designs.
- **Saline Sequestration Leakage Rates:** This scenario incorporates CO_2 leakage rates of less than one percent. However, actual leakage rates have not been extensively documented, and are expected to be difficult to monitor. Increases in CO_2 leakage rates could result in concurrent increases in life cycle GHG emissions.
- **Pre-Existence of Infrastructure:** Some of the infrastructure needed within the boundary of this study, such as a pipeline network suitable for transferring F-T Jet Fuel to the blending facility, was assumed to be pre-existing. No GHG emissions penalty was included for this infrastructure.
- **Comparative Study Results:** The purpose of this study is to provide a comparative evaluation of alternative fuels against baseline 2005 conventional petroleum jet fuel production and use. Results provided for this scenario reflect life cycle emissions from alternative jet fuel production in comparison to that baseline. However, results from this scenario are not intended to provide absolute GHG emissions values; results from this study should be used with caution, when comparing to life cycle analyses having different baseline assumptions and study goals.

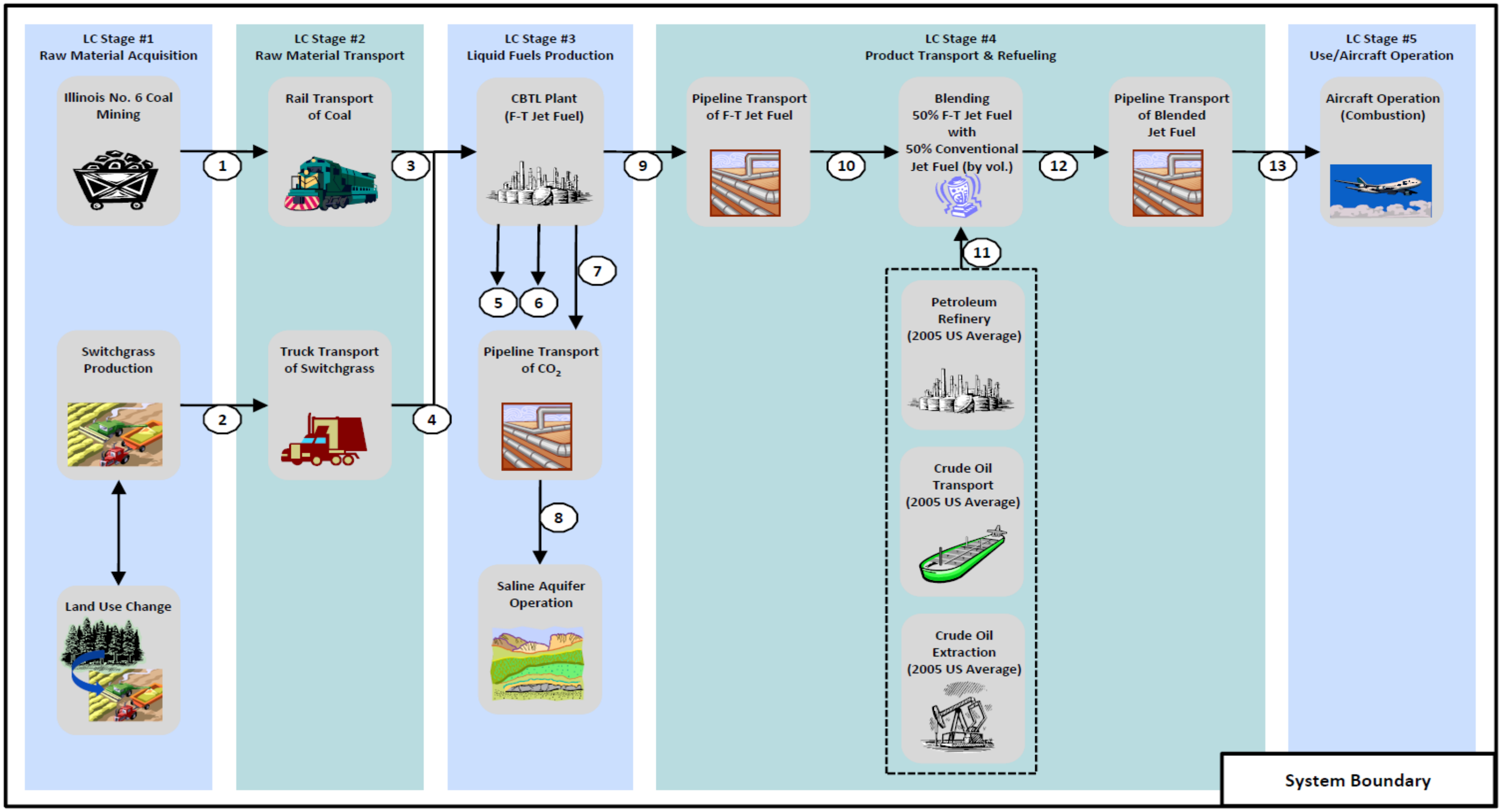
10.9 Scenario 9: 14 Percent Switchgrass, Colbalt F-T Catalyst, Saline Aquifer Sequestration

10.9.1 Scenario Overview

Scenario 9 was designed to evaluate F-T fuels derived from a combination of coal (86 percent by weight) and switchgrass (14 percent by weight) feedstocks. Like other scenarios, Scenario 9 assesses a 1:1 blend F-T and conventional jet fuel (US Average) over a period of 30 years. Illinois No. 6 sub-bituminous coal feedstock is shipped via train to a CBTL facility located in Northern Missouri. Regionally-grown and harvested switchgrass is shipped by diesel truck to the same facility, where it is dried and processed. Unlike Scenarios 1-3 and 6-8, the F-T process employed at the CBTL facility uses a cobalt catalyst with autothermal reforming, and with 91 percent flue gas carbon capture. The F-T process produces a combination of F-T jet fuel (58.1 percent by energy), F-T diesel (28.9 percent by energy), and F-T naphtha (13.1 percent by energy). Captured carbon dioxide is conveyed via a 100 mile pipeline to a saline aquifer carbon dioxide sequestration site where it is injected into the ground and eventually sequestered. Finally, the F-T jet fuel is conveyed via pipeline from the CBTL Facility to a separate blending facility, located at the Woods River Refinery in Illinois. Here it is blended with conventional jet fuel and shipped via pipeline to Chicago O'Hare Airport. Alternatively, the blended fuel may be shipped via a combination of pipeline and tanker truck to Chicago O'Hare and smaller regional airports. Scenario 4 is most closely related to Scenario 4, which also incorporates coal and biomass using cobalt F-T catalyst. Table 174 provides an overview of key values for Scenario 9.

Table 174. Scenario 9 Overview

Item		Scenario Property		
Study Properties				
Functional Unit		1 MJ of Blended F-T Jet Fuel Consumed		
Blended F-T Jet Fuel		4,010 MJ/bbl		
F-T Jet Fuel		50 percent of final product (by volume)		
Conventional Jet Fuel (US Average)		50 percent of final product (by (volume)		
Temporal Boundary		30 years		
CBTL Facility Properties				
Plant Location		Northern Missouri		
Daily Production Capacity		30,000 bbl/d		
F-T Catalyst Type		Cobalt		
Autothermal Reforming		Yes		
Tail Gas Recycle		Yes		
Carbon Capture		91 percent in flue gas		
Optimized for Maximum F-T Jet Fuel Production		No		
Item	**Value**	**Units**	**Value**	**Units**
Energy Feedstock Inputs to CBTL Facility				
Coal, Illinois No. 6	11,889	short tons/day	86%	percent by mass
Biomass, Switchgrass	1,602	short tons/day	14%	percent by mass
Product Outputs from CBTL Plant				
CBTL Plant Liquid Product Output	30,000	bbl/d	100%	percent by energy
CBTL Plant F-T Jet Fuel Production	17,363	bbl/d	58.1%	percent by energy
CBTL Plant F-T-Diesel Fuel Production	8,302	bbl/d	28.9%	percent by energy
CBTL Plant F-T Naphtha Production	4,335	bbl/d	13.1%	percent by energy
Carbon Management Strategy: CO_2-Enhanced Oil Recovery (CO_2-EOR)				
Storage Location	N/A		N/A	N/A
Carbon Dioxide Sequestered	N/A	N/A	N/A	N/A
Crude Oil Production	N/A	N/A	N/A	N/A
Natural Gas Liquids Production	N/A	N/A	N/A	N/A
Carbon Management Strategy: Saline Aquifer				
Storage Location	Relative to CBTL Facility		100	miles from CBTL Facility
Carbon Dioxide Sequestered	16,103	short tons/day	99.5%	percent of CO_2 received
Product Transport to Airport				
F-T Jet Fuel Pipeline Transport to Wood River, Il Refinery	23,618	bbl/d	225	miles
Blended F-T Jet Fuel Pipeline Transport to Chicago O'Hare Airport	24,341	bbl/d	245	miles



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (dry)	50.7	g/MJ LHV	6	F-T Naphtha	2.48	g/MJ LHV	11	Conv. Jet Fuel	11.8	g/MJ LHV
2	Switchgrass (dry)	7.69	g/MJ LHV	7	Supercritical CO_2	77.7	g/MJ LHV	12	Blended Jet Fuel	22.8	g/MJ LHV
3	Illinois No. 6 Coal (dry)	50.7	g/MJ LHV	8	Supercritical CO_2	77.3	g/MJ LHV	13	Blended Jet Fuel	22.8	g/MJ LHV
4	Switchgrass (dry)	7.69	g/MJ LHV	9	F-T Jet Fuel	11.0	g/MJ LHV				
5	F-T Diesel	5.47	g/MJ LHV	10	F-T Jet Fuel	11.0	g/MJ LHV				

Figure 93. Scenario 9: System Boundary and Major Flows (g/MJ Jet Fuel Combusted, LHV)

10.9.2 Life Cycle GHG Results

Lifecycle GHG results are presented below for the deterministic analysis using the best estimate for each modeling parameter, probabilistic uncertainty analysis using the defined uncertainty ranges and probability distributions sampled approximately 2,000 times using a Monte Carlo simulation, and sensitivity analysis to determine the key modeling parameters within the life cycle with greatest influence on the results.

10.9.2.1 Deterministic Analysis Results

Allocated results are tabulated in terms of life cycle sub-categories in Table 175 for both energy allocation and system expansion/displacement allocation method. Total unallocated CO_2e emissions are also provided along with each allocated result to assist understanding of the effect of allocation on each final result. The unallocated results do not represent the life cycle GHG result for 1 MJ of blended F-T Jet Fuel consumed. Unallocated results represent the total GHG emissions released to the atmosphere to produce the suite of co-products produced within the study boundary.

The deterministic analysis results in an 8 percent reduction in life cycle GHG emissions in comparison to a conventional jet fuel baseline of 87.4 g CO_2e/MJ jet fuel combusted, LHV when allocated by energy. Allocation of the co-products using the displacement method results a 14 percent reduction in the life cycle GHG profile compared to conventional jet fuel baseline. Thus the deterministic results of this study show that the life cycle GHG profile for Scenario 9 is 14 percent to 8 percent below the conventional jet fuel baseline.

Table 175. Scenario 9 Deterministic Analysis Results (Using IPCC 2007 GWP)

Life Cycle Stage Sub-categories	Unallocated CO_2e Emissions[1]		CO_2e Emissions Allocated by Energy		CO_2e Emissions Allocated by Displacement	
	g/MJ	%	g/MJ	%	g/MJ	%
LC Stage 1a: Illinois No. 6 Coal Acquisition	4.5	5.5%	2.6	3.3%	3.5	4.7%
LC Stage 2a: Coal Transport	0.8	1.0%	0.4	0.5%	0.6	0.8%
LC Stage 1b: Switchgrass Biomass Production	-12.5	-15.4%	-7.3	-9.1%	-15.2	-20.3%
LC Stage 1c: Direct Land Use	-0.3	-0.4%	-0.2	-0.3%	-0.4	-0.5%
LC Stage 1c: Indirect Land Use	1.2	1.5%	0.7	0.9%	0.9	1.2%
LC Stage 2b: Switchgrass Transport	0.3	0.4%	0.2	0.3%	0.2	0.3%
LC Stage 3a: CBTL Facility	8.3	10.2%	4.8	6.0%	6.5	8.7%
LC Stage 3b: Supercritical CO_2 Transport	0	0.0%	0	0.0%	0	0.0%
LC Stage 3c: Enhanced Oil Recovery (EOR)	0	0.0%	0	0.0%	0	0.0%
LC Stage 3d: Supercritical CO_2 Sequestration	0.5	0.6%	0.3	0.4%	0.4	0.5%
LC Stage 4: F-T Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 4: Conventional Jet Fuel Life Cycle	6.9	8.5%	6.9	8.6%	6.9	9.2%
LC Stage 4: Blended Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 5: Jet Fuel Use	71.3	87.9%	71.3	89.1%	71.3	95.1%
Life Cycle Total:	81.1	100.0%	80	100.0%	75	100.0%

1. Unallocated results represent all co-products produced within the system boundary therefore do not represent the life cycle GHG results for 1 MJ of blended F-T jet fuel consumed. The unallocated results are presented only to illustrate the effect of allocation.

Results by life cycle stage contribution show that fuel combustion (use phase) accounts for the majority of life cycle GHG emissions for both energy allocation (89% of total life cycle emissions) and displacement (95 percent of total lifecycle emissions) respectively. Excluding the use phase, the upstream life cycle stage with the next highest life cycle GHG contribution does not differ by the method of co-product allocation. The next largest contributor for both allocation methods is the conventional jet fuel production life cycle followed by CBTL operation. Interestingly, the CBTL facility contributes only 6.0 percent to 8.7 percent to the total life cycle GHG profile, depending on method of allocation.

10.9.2.2 Probabilistic Uncertainty Analysis Results

Table 176 presents summary statistics for probabilistic CO_2e emissions for Scenario 9 (14 percent switchgrass, cobalt F-T catalyst, normal product slate, and sequestration) along with the "best estimate" (i.e., the deterministic result). Figure 94 presents the probabilistic results in a "box and whisker" plot. Table 176 has the same structure as Table 141, while Figure 94 has the same structure as Figure 66**.**

Scenario 9 provides a convenient comparison point to Scenario 4: Scenario 9 includes CO_2 sequestration as a carbon management strategy, rather than CO_2 EOR. As shown, median CO_2e emissions values are substantially below conventional jet fuel emissions for both energy and displacement allocation. Median emissions under energy allocation are lower by 7.3 g CO_2e/MJ LHV, while median emissions under displacement allocation are lower than conventional jet fuel emissions by 12.3 g CO_2e/MJ LHV. For both energy and displacement allocation, the entire distribution of CO_2e emissions is substantially below the conventional jet fuel value. Similar to other scenarios that include CO_2 sequestration, a comparison of results from Scenario 4 to Scenario 9 underscores that CO_2 sequestration is more effective than CO_2-EOR at lowering lifecycle CO_2 emissions, as relevant to this study.

Table 176. Scenario 9 Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

Quantity	CO_2e Emissions Allocated by Energy (g CO_2e/MJ LHV)	CO_2e Emissions Allocated by Displacement (g CO_2e/MJ LHV)	Combined CO_2e Emissions (g CO_2e/MJ LHV)
Minimum	78.4	72.3	72.3
25th Percentile	79.7	74.5	75.2
Median	80.1	75.1	79.0
75th Percentile	80.4	75.8	80.1
Maximum	81.6	77.8	81.6
Best Estimate	80.0	75.0	77.5
Conventional Jet Fuel	87.4	87.4	87.4

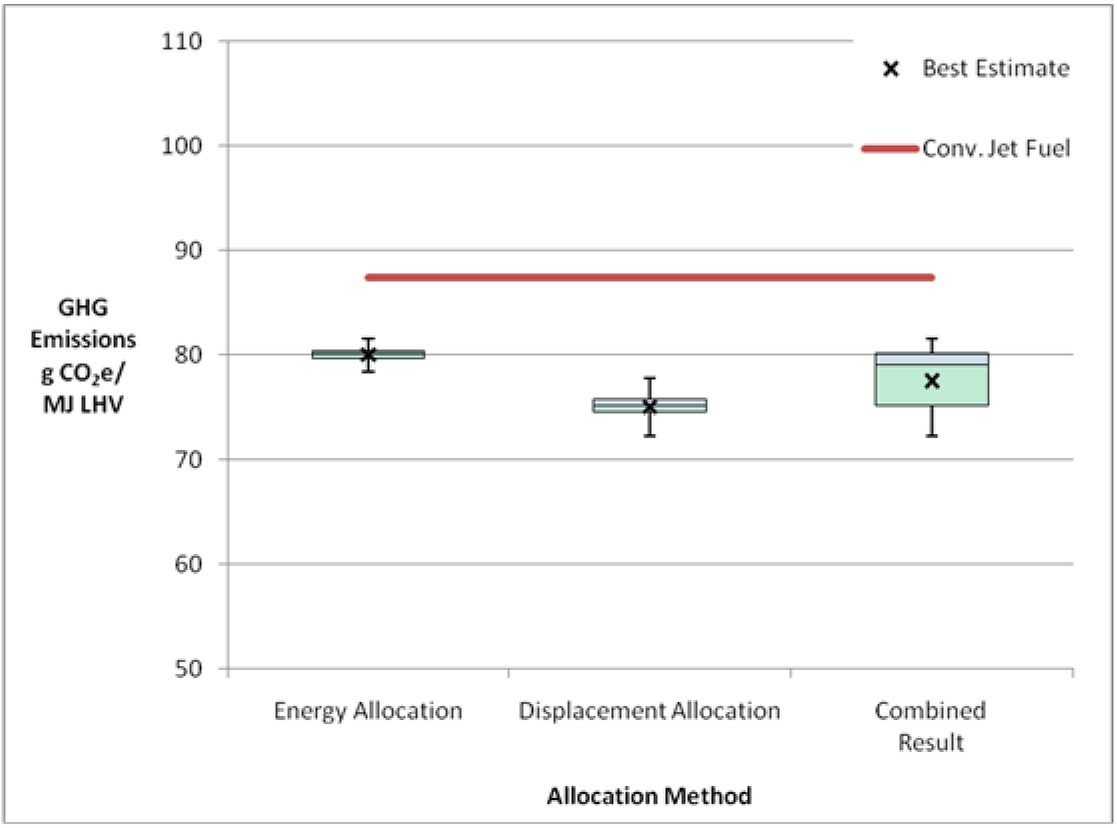


Figure 94. Scenario 9 Box and Whisker Plot of Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

10.9.2.3 Sensitivity Analysis Results

Sensitivity analysis results were calculated for both co-product allocation procedures (energy allocation and displacement method) by adjusting each modeling parameter independently between the minimum and maximum values to determine the effect on the final life cycle GHG result. The 24 modeling parameters with the greatest effect on the results was determined and ranked from highest to lowest based on their absolute difference. The results are reported in both tabular and graphical form in Table 177 and Figure 95 for the energy allocation results and Table 178 and Figure 96 for the displacement method results. All results are reported based on the IPCC 2007 global warming potentials.

Table 177. Scenario 9 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	78.1	78.6	0.562
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.06	6.99	7.13	78.5	78.2	0.352
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	78.5	78.2	0.266
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	78.3	78.5	0.212
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	78.3	78.4	0.192
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air_3c	kg/kg	0.005	0	0.01	78.3	78.4	0.176
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	78.3	78.4	0.172
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	78.3	78.4	0.117
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	78.4	78.3	0.109
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	78.3	78.4	0.106
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	78.3	78.4	0.0944
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	78.3	78.4	0.091
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	78.3	78.4	0.0868
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	78.3	78.4	0.0633
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	78.3	78.4	0.0492

Table 177. Scenario 9 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	78.3	78.4	0.0346
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	78.3	78.4	0.0253
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	78.3	78.4	0.00976
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	78.4	78.3	0.00611
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	78.4	78.4	0.00594
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	100	90	110	78.3	78.4	0.00473
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	78.3	78.4	0.00472
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	78.3	78.4	0.00436
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	78.3	78.4	0.0042

Table 178. Scenario 9 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	7.06	6.99	7.13	67.1	65.6	1.54
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	65.9	67.1	1.21
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	67	65.8	1.17
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	65.9	66.8	0.848
Fraction of CO_2 Delivered to EOR Facility that is Lost to Atmosphere	Frac_CO2_EOR_emit_air_3c	kg/kg	0.005	0	0.01	66	66.8	0.779
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	66	66.7	0.759
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	66.6	65.9	0.754
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	66.1	66.6	0.562
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	66.2	66.6	0.417
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	66.2	66.6	0.402
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	66.2	66.5	0.28
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	66.2	66.5	0.25
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	66.3	66.5	0.217
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	66.3	66.5	0.117
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	66.3	66.4	0.112

Table 178. Scenario 9 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) ***(Cont'd)***

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	66.3	66.4	0.106
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	66.3	66.4	0.0428
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	66.4	66.4	0.0346
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	66.4	66.4	0.027
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	66.4	66.4	0.0262
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	100	90	110	66.4	66.4	0.0209
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	66.4	66.4	0.0207
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	66.4	66.4	0.0193
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	66.4	66.4	0.0186

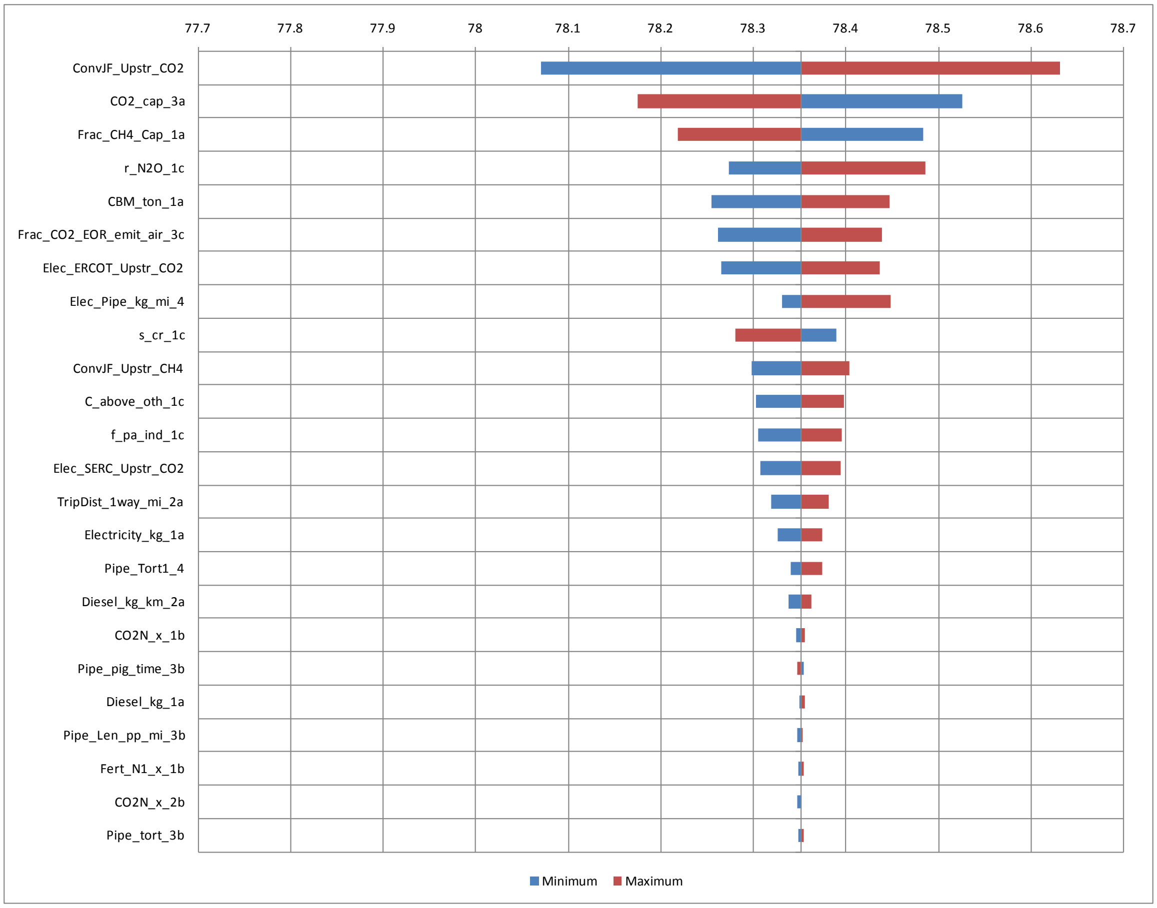


Figure 95. Scenario 9 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

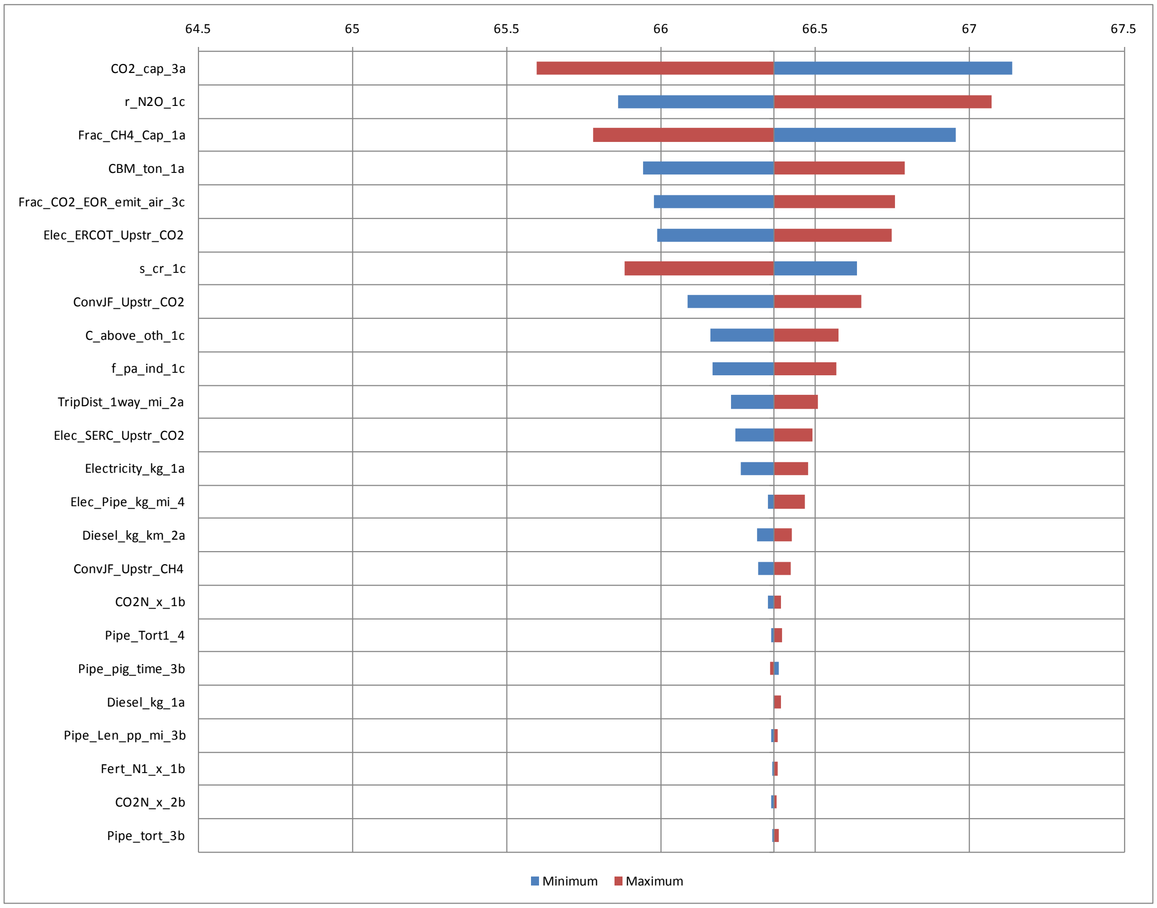


Figure 96. Scenario 9 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

10.9.3 Data Limitations

In terms of broader study limitations, the model boundaries and modeling choices contained in this scenario inform the following study limitations, which should be considered when interpreting final results and conclusions generated from this study:

- **Mine and Mine Methane Emissions:** This scenario presumes that Illinois No. 6 sub-bituminous coal from an underground longwall mine would be used, having an average methane emission rate of 150 scf CH_4/ton with 40 percent capture. Use of an alternative coal type, mine type, methane emission rate, or methane capture rate could increase or decrease mine and mine methane related GHG emissions.
- **Biomass Production:** This scenario presumes that farmed switchgrass would be used as the sole source of biomass. However, alternative sources of biomass could also have been chosen, such as farmed short rotation woody crops or corn stover, or biomass waste streams such as agricultural wastes or logging wastes. The use of alternative farming practices, crop requirements, and/or biomass source could increase or reduce life cycle GHG emissions.

- **Biomass Yields:** This scenario presumes that switchgrass production would yield 4.7 dry tons per acre per year of biomass. However, switchgrass yields reported in the literature are highly variable, in part reflecting farming practices and regional conditions. Higher or lower switchgrass yield values could substantially decrease or increase life cycle land use, respectively.
- **Biomass Transport:** This scenario presumes a 50 mile switchgrass production radius. The intensity of biomass transport emissions is expected to increase with increases in production radius. Therefore, substantial increases in the biomass production radius for this study could result in concurrent increases in transportation related GHG emissions, as well as increases in cost, which under some cases could render a longer distance biomass collection scheme infeasible.
- **CBTL Facility Carbon Capture Rate:** The rate of carbon capture at the F-T facility used for this scenario is 91 percent, which is expected to be a conservative estimate of actual carbon capture rates. However, carbon capture facilities have not been widely implemented at the commercial scale. Therefore, a higher or lower carbon capture rate may apply to some future studies. Increases or decreases in this rate would result in concurrent increases or decreases in life cycle GHG emissions.
- **CBTL Facility Modeling Scenarios:** In order to model the F-T facility, output from a separate ASPEN model was incorporated into the life cycle model used for this study. As a result, the F-T facility model included in this study is static: the workings of the F-T facility cannot be updated or altered to evaluate different F-T facility parameters and setups, without performing substantial additional analysis. The F-T facility results from this study represent specific assumptions, as documented in **Section 6**, and are not necessarily representative of all potential F-T Facility designs.
- **Saline Sequestration Leakage Rates:** This scenario incorporates CO_2 leakage rates of less than one percent. However, actual leakage rates have not been extensively documented, and are expected to be difficult to monitor. Increases in CO_2 leakage rates could result in concurrent increases in life cycle GHG emissions.
- **Pre-Existence of Infrastructure:** Some of the infrastructure needed within the boundary of this study, such as a pipeline network suitable for transferring F-T Jet Fuel to the blending facility, was assumed to be pre-existing. No GHG emissions penalty was included for this infrastructure.
- **Comparative Study Results:** The purpose of this study is to provide a comparative evaluation of alternative fuels against baseline 2005 conventional petroleum jet fuel production and use. Results provided for this scenario reflect life cycle emissions from alternative jet fuel production in comparison to that baseline. However, results from this scenario are not intended to provide absolute GHG emissions values; results from this study should be used with caution, when comparing to life cycle analyses having different baseline assumptions and study goals.

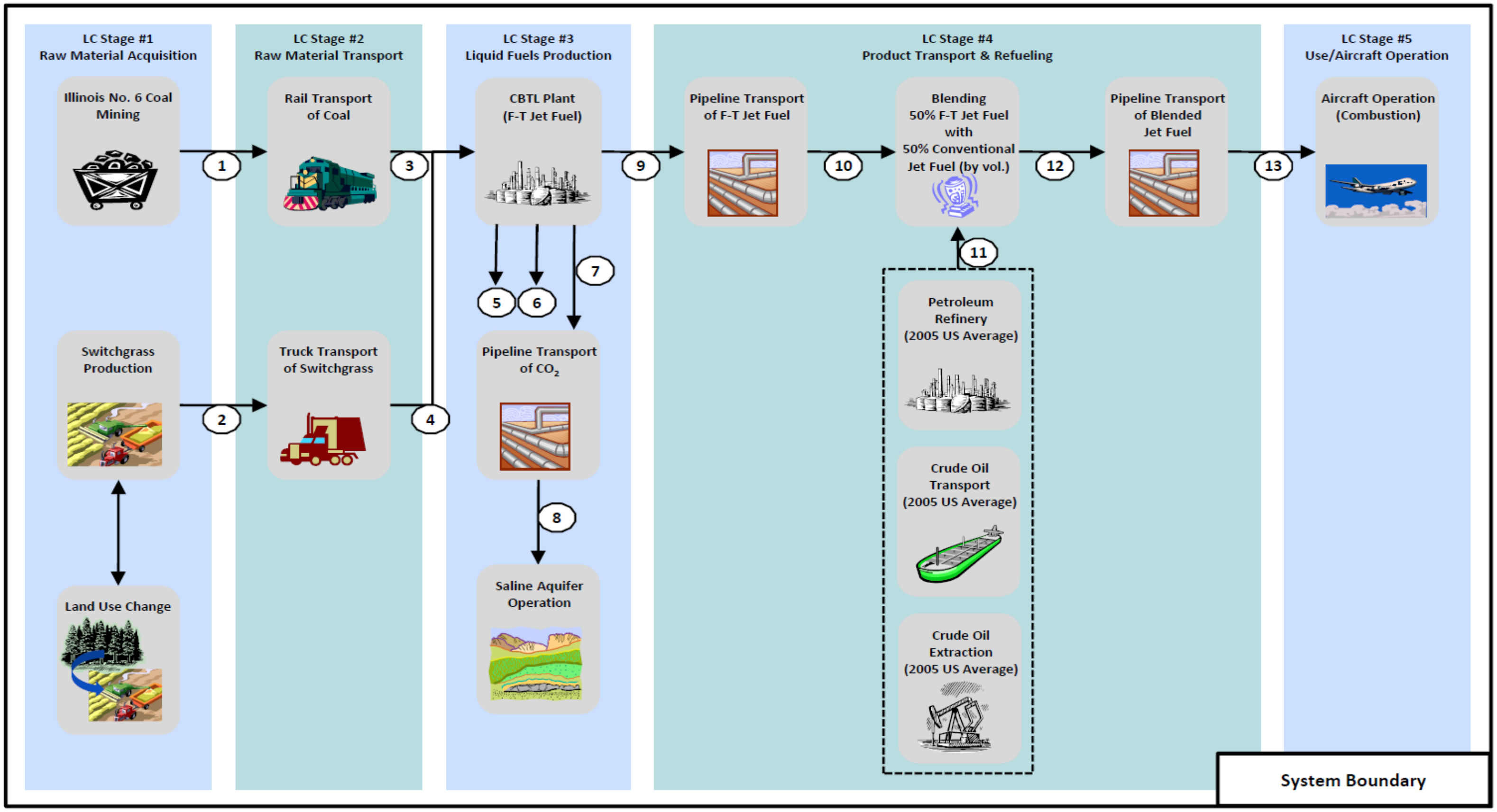
10.10 Scenario 10: 14 Percent Switchgrass, Cobalt F-T Catalyst, Saline Aquifer Sequestration (Optimized for Maximum Jet Fuel Production)

10.10.1 Scenario Overview

Scenario 10 was designed to evaluate a CBTL Facility that is optimized for maximum F-T jet fuels production. Feedstocks are derived from a combination of coal (86 percent by weight) and switchgrass (14 percent by weight). Like other scenarios, Scenario 10 assesses a 1:1 blend F-T and conventional jet fuel (US Average) over a period of 30 years. Illinois No. 6 sub-bituminous coal feedstock is shipped via train to a CBTL facility located in Northern Missouri. Regionally-grown and harvested switchgrass is shipped by diesel truck to the same facility, where it is dried and processed. Unlike Scenarios 1-3 and 6-8, the F-T process employed at the CBTL facility uses a cobalt catalyst with autothermal reforming, and with 91 percent flue gas carbon capture. The F-T process produces a combination of F-T jet fuel (80.3 percent by energy) and F-T naphtha (19.7 percent by energy). Note that under Scenario 10, no F-T diesel fuel is produced. Captured carbon dioxide is conveyed via a 100 mile pipeline to a saline aquifer carbon dioxide sequestration site where it is injected into the ground and eventually sequestered. Finally, the F-T jet fuel is conveyed via pipeline from the CBTL Facility to a separate blending facility, located at the Woods River Refinery in Illinois. Here it is blended with conventional jet fuel and shipped via pipeline to Chicago O'Hare Airport. Alternatively, the blended fuel may be shipped via a combination of pipeline and tanker truck to Chicago O'Hare and smaller regional airports. Scenario 10 is most closely related to Scenario 5, which also incorporates coal and biomass using cobalt F-T catalyst, using an F-T jet fuels optimized CBTL process. Table 179 provides an overview of key values for Scenario 10.

Table 179. Scenario 10 Overview

Item		Scenario Property		
Study Properties				
Functional Unit		1 MJ of Blended F-T Jet Fuel Consumed		
Blended F-T Jet Fuel		4,010 MJ/bbl		
F-T Jet Fuel		50 percent of final product (by volume)		
Conventional Jet Fuel (US Average)		50 percent of final product (by (volume)		
Temporal Boundary		30 years		
CBTL Facility Properties				
Plant Location		Northern Missouri		
Daily Production Capacity		30,000 bbl/d		
F-T Catalyst Type		Cobalt		
Autothermal Reforming		Yes		
Tail Gas Recycle		Yes		
Carbon Capture		91 percent in flue gas		
Optimized for Maximum F-T Jet Fuel Production		Yes		
Item	Value	Units	Value	Units
Energy Feedstock Inputs to CBTL Facility				
Coal, Illinois No. 6	11,798	short tons/day	86%	percent by mass
Biomass, Switchgrass	1,589	short tons/day	14%	percent by mass
Product Outputs from CBTL Plant				
CBTL Plant Liquid Product Output	30,000	bbl/d	100%	percent by energy
CBTL Plant F-T Jet Fuel Production	23,595	bbl/d	80.3%	percent by energy
CBTL Plant F-T-Diesel Fuel Production	0	bbl/d	0%	percent by energy
CBTL Plant F-T Naphtha Production	6,405	bbl/d	19.7%	percent by energy
Carbon Management Strategy: CO_2-Enhanced Oil Recovery (CO_2-EOR)				
Storage Location	N/A		N/A	N/A
Carbon Dioxide Sequestered	N/A	N/A	N/A	N/A
Crude Oil Production	N/A	N/A	N/A	N/A
Natural Gas Liquids Production	N/A	N/A	N/A	N/A
Carbon Management Strategy: Saline Aquifer				
Storage Location	Relative to CBTL Facility		100	miles from CBTL Facility
Carbon Dioxide Sequestered	15,976	short tons/day	99.5%	percent of CO_2 received
Product Transport to Airport				
F-T Jet Fuel Pipeline Transport to Wood River, Il Refinery	32,096	bbl/d	225	miles
Blended F-T Jet Fuel Pipeline Transport to Chicago O'Hare Airport	33,079	bbl/d	245	miles



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (dry)	37.0	g/MJ LHV	6	F-T Naphtha	2.7	g/MJ LHV	11	Conv. Jet Fuel	11.8	g/MJ LHV
2	Switchgrass (dry)	5.61	g/MJ LHV	7	Supercritical CO_2	56.8	g/MJ LHV	12	Blended Jet Fuel	22.8	g/MJ LHV
3	Illinois No. 6 Coal (dry)	36.0	g/MJ LHV	8	Supercritical CO_2	56.4	g/MJ LHV	13	Blended Jet Fuel	22.8	g/MJ LHV
4	Switchgrass (dry)	5.61	g/MJ LHV	9	F-T Jet Fuel	11.0	g/MJ LHV				
5	F-T Diesel	0	g/MJ LHV	10	F-T Jet Fuel	11.0	g/MJ LHV				

Figure 97. Scenario 10: System Boundary and Major Flows (g/MJ Jet Fuel Combusted, LHV)

10.10.2 Life Cycle GHG Results

Lifecycle GHG results are presented below for the deterministic analysis using the best estimate for each modeling parameter, probabilistic uncertainty analysis using the defined uncertainty ranges and probability distributions sampled approximately 2,000 times using a Monte Carlo simulation, and sensitivity analysis to determine the key modeling parameters within the life cycle with greatest influence on the results.

10.10.2.1 Deterministic Analysis Results

Allocated results are tabulated in terms of life cycle sub-categories in Table 180 for both energy allocation and system expansion/displacement allocation method. Total unallocated CO_2e emissions are also provided along with each allocated result to assist understanding of the effect of allocation on each final result. The unallocated results do not represent the life cycle GHG result for 1 MJ of blended F-T Jet Fuel consumed. Unallocated results represent the total GHG emissions released to the atmosphere to produce the suite of co-products produced within the study boundary.

Table 180. Scenario 10 Deterministic Analysis Results (Using IPCC 2007 GWP)

Life Cycle Stage Sub-categories	Unallocated CO_2e Emissions[1]		CO_2e Emissions Allocated by Energy		CO_2e Emissions Allocated by Displacement	
	g/MJ	%	g/MJ	%	g/MJ	%
LC Stage 1a: Illinois No. 6 Coal Acquisition	3.3	4.1%	2.6	3.2%	3	3.8%
LC Stage 2a: Coal Transport	0.6	0.7%	0.5	0.6%	0.5	0.6%
LC Stage 1b: Switchgrass Biomass Production	-9.1	-11.2%	-7.3	-9.0%	-9.8	-12.3%
LC Stage 1c: Direct Land Use	-0.2	-0.2%	-0.2	-0.2%	-0.2	-0.3%
LC Stage 1c: Indirect Land Use	0.9	1.1%	0.7	0.9%	0.8	1.0%
LC Stage 2b: Switchgrass Transport	0.2	0.2%	0.2	0.2%	0.2	0.3%
LC Stage 3a: CBTL Facility	6.9	8.5%	5.6	6.9%	6.4	8.0%
LC Stage 3b: Supercritical CO_2 Transport	0	0.0%	0	0.0%	0	0.0%
LC Stage 3c: Enhanced Oil Recovery (EOR)	0	0.0%	0	0.0%	0	0.0%
LC Stage 3d: Supercritical CO_2 Sequestration	0.4	0.5%	0.3	0.4%	0.3	0.4%
LC Stage 4: F-T Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 4: Conventional Jet Fuel Life Cycle	6.9	8.5%	6.9	8.6%	6.9	8.7%
LC Stage 4: Blended Jet Fuel Transport	0.1	0.1%	0.1	0.1%	0.1	0.1%
LC Stage 5: Jet Fuel Use	71.3	87.8%	71.3	88.4%	71.3	89.6%
Life Cycle Total:	81.2	100.0%	80.7	100.0%	79.6	100.0%

1. Unallocated results represent all co-products produced within the system boundary therefore do not represent the life cycle GHG results for 1 MJ of blended F-T jet fuel consumed. The unallocated results are presented only to illustrate the effect of allocation.

The deterministic analysis results in an 8 percent reduction in life cycle GHG emissions in comparison to a conventional jet fuel baseline of 87.4 g CO_2e/MJ jet fuel combusted, LHV when allocated by energy. Allocation of the co-products using the displacement method results a 9 percent reduction in the life cycle GHG profile compared to conventional jet fuel baseline. Thus the deterministic results of this study show that the life cycle GHG profile for Scenario 10 is 9 percent to 8 percent below the conventional jet fuel baseline.

Results by life cycle stage contribution show that fuel combustion (use phase) accounts for the majority of life cycle GHG emissions for both energy allocation (88 percent of total life cycle

emissions) and displacement (90 percent of total lifecycle emissions) respectively. Excluding the use phase, the upstream life cycle stage with the next highest life cycle GHG contribution does not differ by the method of co-product allocation. The next largest contributor for both allocation methods is the conventional jet fuel production life cycle followed by CBTL operation. Interestingly, the CBTL facility contributes only 6.9 percent to 8.0 percent to the total life cycle GHG profile, depending on method of allocation.

10.10.2.2 Probabilistic Uncertainty Analysis Results

Table 181 presents summary statistics for probabilistic CO_2e emissions for Scenario 10 (13 percent switchgrass, cobalt catalyst, maximize production of F-T jet fuel and sequestration) along with the "best estimate" (i.e., the deterministic result). Figure 98 presents the probabilistic results in a "box and whisker" plot. Table 181 has the same structure as Table 141, and Figure 98 has the same structure as Figure 66.

Scenario 10 provides a comparison point to Scenario 5: Scenario 10 includes CO_2 sequestration as a carbon management strategy, rather than CO_2 EOR. As shown, median CO_2e emissions values are below conventional jet fuel emissions for both energy and displacement allocation. Median emissions under energy allocation are lower by 6.6 g CO_2e/MJ LHV, while median emissions under displacement allocation are lower than conventional jet fuel emissions by 7.7 g CO_2e/MJ LHV. For both energy and displacement allocation, the entire distribution of CO_2e emissions is below the conventional jet fuel value. Similar to other scenarios that include CO_2 sequestration, a comparison of results from Scenario 5 to Scenario 10 underscores that CO_2 sequestration is more effective than CO_2-EOR at lowering lifecycle CO_2 emissions, as relevant to this study.

Table 181. Scenario 10 Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

Quantity	CO_2e Emissions Allocated by Energy (g CO_2e/MJ LHV)	CO_2e Emissions Allocated by Displacement (g CO_2e/MJ LHV)	Combined CO_2e Emissions (g CO_2e/MJ LHV)
Minimum	79.1	77.7	77.7
25th Percentile	80.4	79.3	79.7
Median	80.8	79.7	80.3
75th Percentile	81.1	80.2	80.8
Maximum	82.5	81.8	82.5
Best Estimate	80.7	79.6	80.2
Conventional Jet Fuel	87.4	87.4	87.4

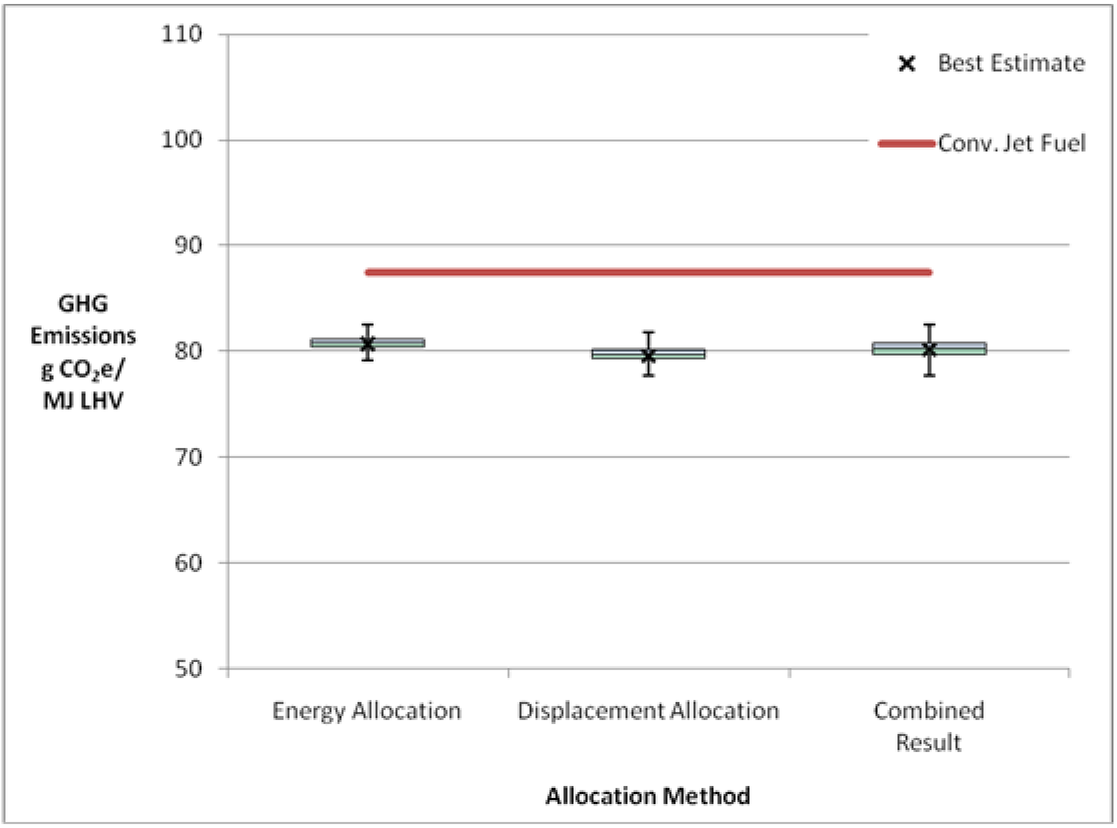


Figure 98. Scenario 10 Box and Whisker Plot of Probabilistic Uncertainty Analysis Results (Using IPCC 2007 GWP)

10.10.2.3 Sensitivity Analysis Results

Sensitivity analysis results were calculated for both co-product allocation procedures (energy allocation and displacement method) by adjusting each modeling parameter independently between the minimum and maximum values to determine the effect on the final life cycle GHG result. The 24 modeling parameters with the greatest effect on the results was determined and ranked from highest to lowest based on their absolute difference. The results are reported in both tabular and graphical form in Table 182 and Figure 99 for the energy allocation results and Table 183 and Figure 100 for the displacement method results. All results are reported based on the IPCC 2007 global warming potentials.

Table 182. Scenario 10 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	81.6	80.6	0.939
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	5.16	5.1	5.21	81.5	80.6	0.907
N_2O emissions from nitrogen fertilizer	r_N2O_1c	kg N_2O/kg N	0.02	0.003	0.05	80.8	81.6	0.751
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	80.7	81.4	0.679
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	80.8	81.4	0.562
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS_3d	tonne/tonne	0.005	0	0.01	80.9	81.3	0.456
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	81.2	80.8	0.386
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	80.9	81.3	0.334
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	80.9	81.2	0.322
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	81	81.2	0.224
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	81	81.2	0.208
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	81	81.2	0.174
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	81.1	81.2	0.117
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	81.1	81	0.116

Table 182. Scenario 10 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) ***(Cont'd)***

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/ MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Upstream CH_4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH_4/kWh	0.00361	0.00343	0.00379	81	81.1	0.106
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	775	698	853	81	81.1	0.0913
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	81	81.1	0.0893
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	81.1	81.1	0.0811
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	81.1	81.1	0.0346
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	81.1	81.1	0.0345
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	81.1	81.1	0.021
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	81.1	81.1	0.0167
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	81.1	81.1	0.0154
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	81.1	81.1	0

Table 183. Scenario 10 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Fraction of Coal Bed Methane Captured	Frac_CH4_Cap_1a	kg/kg	0.4	0.2	0.6	80.7	79.5	1.17
CO_2 Captured for EOR or Sequestration	CO2_cap_3a	kg/kg F-T jet fuel	5.16	5.1	5.21	80.7	79.6	1.13
N2O emissions from nitrogen fertilizer	r_N2O_1c	kg N2O/kg N	0.02	0.003	0.05	79.7	80.8	1.01
Coal Bed Methane Generated in scf per Ton of Useful Coal Produced	CBM_ton_1a	scf/ton	150	120	180	79.7	80.6	0.847
Fraction of CO_2 Captured at CBTL that is Lost to Atmosphere During Injection and Storage at Sequestration Site	CO2_FracLost_SeqS_3d	tonne/tonne	0.005	0	0.01	79.8	80.4	0.568
Upstream CO_2 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CO2	kg CO_2/kWh	0.478	0.454	0.502	79.9	80.4	0.562
Share of land previously crop land	s_cr_1c		0.239	0.15	0.4	80.3	79.8	0.561
Carbon in above ground "other" (including forest) biomass	C_above_oth_1c	tonne C/ha	40	30	50	79.9	80.3	0.416
Fraction of pasture land converted directly to switchgrass that is indirectly converted back to pasture land	f_pa_ind_1c		0.3	0.2	0.4	79.9	80.3	0.401
One-way Distance from Mine to CBTL Facility	TripDist_1way_mi_2a	mi	200	150	250	80	80.3	0.279
Upstream CO_2 Emitted per kWh SERC Electricity Produced	Elec_SERC_Upstr_CO2	kg CO_2/kWh	0.762	0.686	0.838	80	80.3	0.249
Electricity Used per kg of Useful Coal Produced	Electricity_kg_1a	kWh/kg coal	0.0331	0.0298	0.0364	80	80.2	0.217
Time Between Pigging Inspections	Pipe_pig_time_3b	years	5	4	6	80.2	80.1	0.145

Table 183. Scenario 10 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed) *(Cont'd)*

Variable Name	Variable Symbol	Units	Input Values			Results: CO_2e Emissions (g CO_2e/MJ Blended Jet Fuel Consumed)		
			Best Estimate	Minimum	Maximum	Minimum	Maximum	Abs. Diff.
Electricity Required to Pump Fuel Through Pipeline Per kg of Fuel and mile Traveled	Elec_Pipe_kg_mi_4	kWh/kg-mi	0.0000277	0.0000249	0.0000416	80.1	80.2	0.117
Point-to-point Length of Pipeline from CBTL Facility to EOR Operations or Sequestration Site	Pipe_Len_pp_mi_3b	mi	775	698	853	80.1	80.2	0.114
Diesel Fuel Used per kg of Coal per km Transported	Diesel_kg_km_2a	kg diesel/kg-km	0.00000521	0.00000469	0.00000573	80.1	80.2	0.111
Upstream CH4 Emitted per kg Conventional Jet Fuel Produced	ConvJF_Upstr_CH4	kg CH4/kWh	0.00361	0.00343	0.00379	80.1	80.2	0.106
Tortuosity Factor for Pipeline	Pipe_tort_3b		0.1	0.05	0.2	80.1	80.2	0.101
Carbon dioxide (CO_2): Direct emissions from farm activities	CO2N_x_1b	kg/tonne	21	17.3	25	80.1	80.2	0.0429
Pipeline Tortuosity	Pipe_Tort1_4		0.1	0.05	0.2	80.1	80.2	0.0346
Diesel Fuel Used per kg of Useful Coal Produced	Diesel_kg_1a	kg dies/kg coal	0.000263	0.000237	0.000394	80.1	80.2	0.0262
Fertilizer as nitrogen, at farm	Fert_N1_x_1b	kg/tonne	12.9	12.3	13.7	80.1	80.1	0.0207
Carbon dioxide (CO_2): non-biogenic, to air	CO2N_x_2b	kg/tonne	26.4	24.3	27.7	80.1	80.1	0.0192
Upstream CO_2 Emitted per kWh ERCOT Electricity Produced	Elec_ERCOT_Upstr_CO2	kg CO_2/kWh	0.752	0.677	0.828	80.1	80.1	0

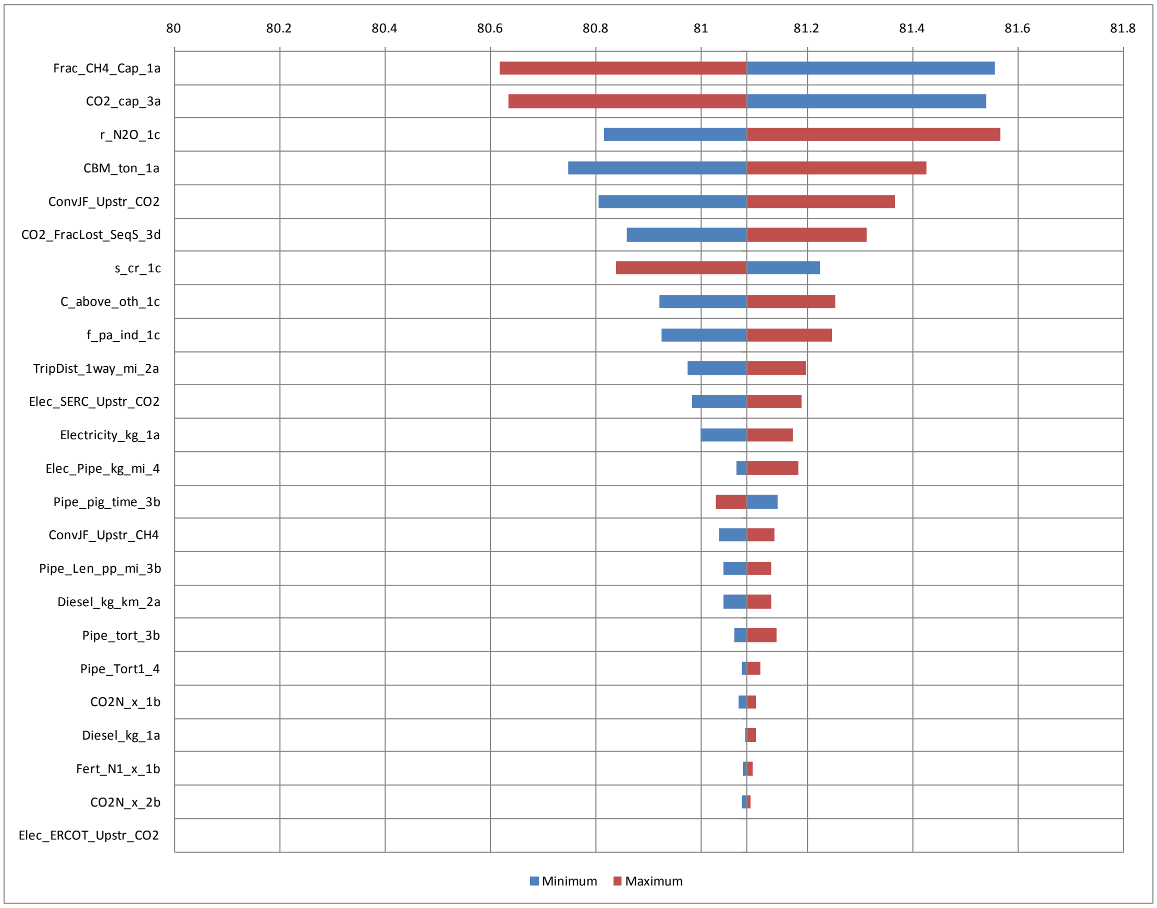


Figure 99. Scenario 10 Sensitivity Analysis Results with Co-Product Allocation by Energy (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

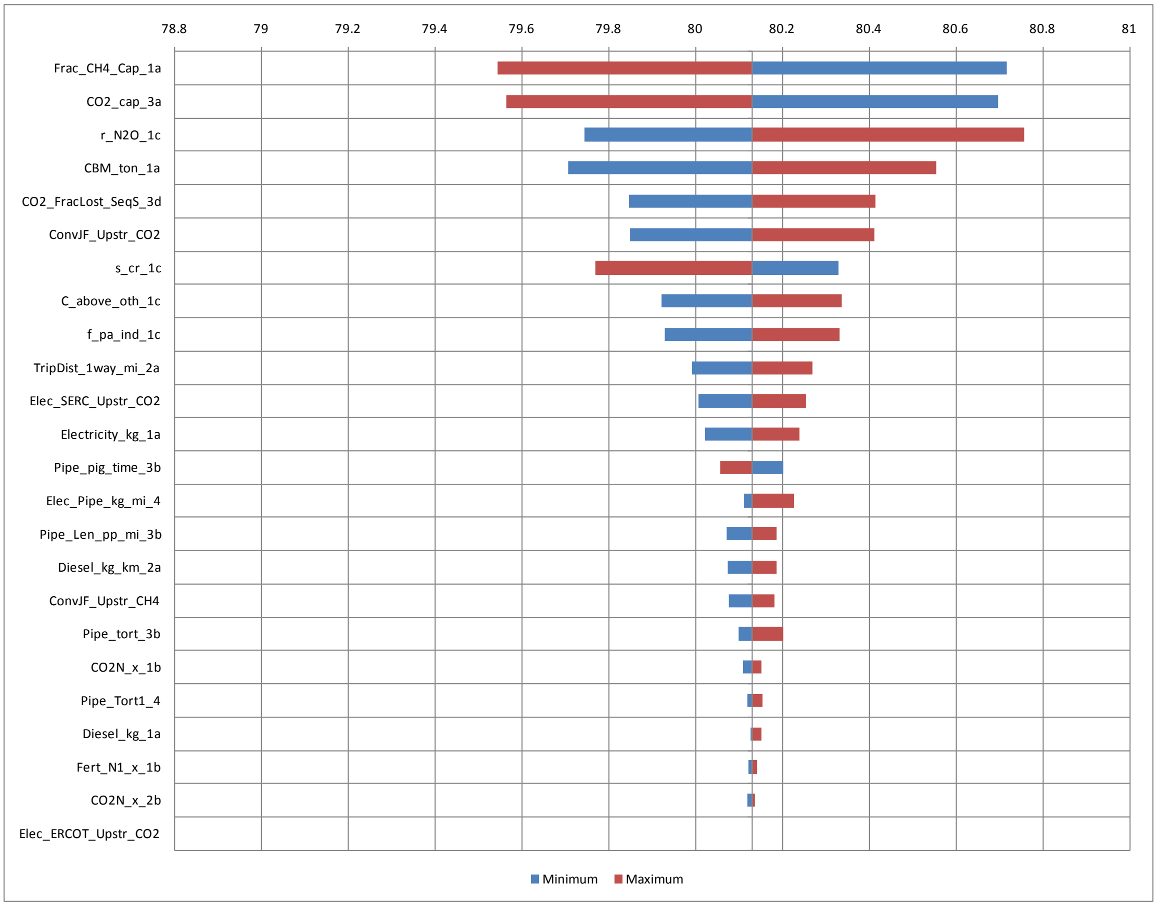


Figure 100. Scenario 10 Sensitivity Analysis Results with Co-Product Allocation by Displacement (Using IPCC 2007 GWP) (g CO_2e/MJ Blended Jet Fuel Consumed)

10.10.3 Data Limitations

In terms of broader study limitations, the model boundaries and modeling choices contained in this scenario inform the following study limitations, which should be considered when interpreting final results and conclusions generated from this study:

- **Mine and Mine Methane Emissions:** This scenario presumes that Illinois No. 6 sub-bituminous coal from an underground longwall mine would be used, having an average methane emission rate of 150 scf CH_4/ton with 40 percent capture. Use of an alternative coal type, mine type, methane emission rate, or methane capture rate could increase or decrease mine and mine methane related GHG emissions.
- **Biomass Production:** This scenario presumes that farmed switchgrass would be used as the sole source of biomass. However, alternative sources of biomass could also have been chosen, such as farmed short rotation woody crops or corn stover, or biomass waste streams such as agricultural wastes or logging wastes. The use of alternative farming practices, crop requirements, and/or biomass source could increase or reduce life cycle GHG emissions.

- **Biomass Yields:** This scenario presumes that switchgrass production would yield 4.7 dry tons per acre per year of biomass. However, switchgrass yields reported in the literature are highly variable, in part reflecting farming practices and regional conditions. Higher or lower switchgrass yield values could substantially decrease or increase life cycle land use, respectively.
- **Biomass Transport:** This scenario presumes a 50 mile switchgrass production radius. The intensity of biomass transport emissions is expected to increase with increases in production radius. Therefore, substantial increases in the biomass production radius for this study could result in concurrent increases in transportation related GHG emissions, as well as increases in cost, which under some cases could render a longer distance biomass collection scheme infeasible.
- **CBTL Facility Carbon Capture Rate:** The rate of carbon capture at the F-T facility used for this scenario is 91 percent, which is expected to be a conservative estimate of actual carbon capture rates. However, carbon capture facilities have not been widely implemented at the commercial scale. Therefore, a higher or lower carbon capture rate may apply to some future studies. Increases or decreases in this rate would result in concurrent increases or decreases in life cycle GHG emissions.
- **CBTL Facility Modeling Scenarios:** In order to model the F-T facility, output from a separate ASPEN model was incorporated into the life cycle model used for this study. As a result, the F-T facility model included in this study is static: the workings of the F-T facility cannot be updated or altered to evaluate different F-T facility parameters and setups, without performing substantial additional analysis. The F-T facility results from this study represent specific assumptions, as documented in **Section 6**, and are not necessarily representative of all potential F-T Facility designs.
- **Saline Sequestration Leakage Rates:** This scenario incorporates CO_2 leakage rates of less than one percent. However, actual leakage rates have not been extensively documented, and are expected to be difficult to monitor. Increases in CO_2 leakage rates could result in concurrent increases in life cycle GHG emissions.
- **Pre-Existence of Infrastructure:** Some of the infrastructure needed within the boundary of this study, such as a pipeline network suitable for transferring F-T Jet Fuel to the blending facility, was assumed to be pre-existing. No GHG emissions penalty was included for this infrastructure.
- **Comparative Study Results:** The purpose of this study is to provide a comparative evaluation of alternative fuels against baseline 2005 conventional petroleum jet fuel production and use. Results provided for this scenario reflect life cycle emissions from alternative jet fuel production in comparison to that baseline. However, results from this scenario are not intended to provide absolute GHG emissions values; results from this study should be used with caution, when comparing to life cycle analyses having different baseline assumptions and study goals.

11.0 DISCUSSION AND CONCLUSIONS

This section provides an overall comparison of the results from the 10 modeled scenarios, as well as a brief discussion of key trends that were identified during the analysis that was completed in support of this study. The discussion and conclusions drawn in this section are based on the results provided in **Section 10,** and consider details related to process flows and emissions values discussed in **Sections 4** through **8**.

11.1 Comparison of Modeled Scenarios

Lifecycle GHG emissions results of the 10 modeled scenarios span a range of values from55.2 (Scenario 8, displacement; best estimate value) to 98.2 g CO_2e/MJ LHV (Scenario 1, displacement; best estimate value). These values range from 63 percent to 112 percent of conventional petroleum jet fuel lifecycle GHG emissions, which are estimated at 87.4 CO_2e/MJ LHV. The following discussion provides a brief overview of key differentiators among the 10 scenarios, and importance to estimated lifecycle GHG emissions. Deterministic allocated results for the 10 scenarios are presented in Figure 101.

Figure 102 presents a box and whisker chart of the combined result for each scenario, in order to provide easy comparison among scenarios. As shown, the distributions for Scenarios 2, 3, 7, 8, 9, and 10, are entirely below the conventional jet fuel emissions. For all other scenarios, the distributions span the jet fuel baseline, but most of the distribution is below the jet fuel baseline.

Differences in lifecycle GHG emissions among the 10 scenarios were first and foremost informed by the percentage of switchgrass biomass that was utilized. For both EOR and saline sequestration carbon management strategies, the scenarios with the highest lifecycle GHG emissions were those that relied solely on coal as feedstock (Scenarios 1 and 6). Similarly, for both EOR and saline sequestration, the scenarios with the lowest lifecycle GHG emissions were those that had the highest proportion of biomass (Scenarios 3 and 8). Scenarios relying on intermediary amounts of biomass as feedstock resulted in intermediary lifecycle GHG emissions, for both EOR and saline sequestration carbon management strategies.

The mode of allocation employed also had a substantial effect on GHG emissions for some Scenarios, in particular Scenarios 1, 3, and 8. A comparison of allocation strategies for Scenario 1 is particularly interesting, because results for energy allocation indicate a lifecycle GHG emissions profile that is below the conventional jet fuel baseline, while displacement allocation is above that baseline, and therefore not in compliance with Air Force alternative fuels requirements. These results highlight the importance of carefully considering the most appropriate allocation strategy for a given fuels production scenario.

Carbon management also informed lifecycle GHG emissions for most of the scenarios. For instance, comparing Scenarios 2 to 7, 3 to 8, 4 to 9, and 5 to 10 (these pairs of scenarios are identical except for carbon management strategy), lifecycle GHG emissions are consistently lower for saline aquifer sequestration, as compared with EOR.

Among contributions from individual LC Stages, blended jet fuel combustion (LC Stage #5) remains the largest contributor to lifecycle GHG emissions after application of allocation (83-86 percent of Scenario 2 lifecycle emissions, varying by allocation method). In fact, application of allocation decreases the emissions seen from LC Stages #1-4 of the lifecycle, thus increasing the

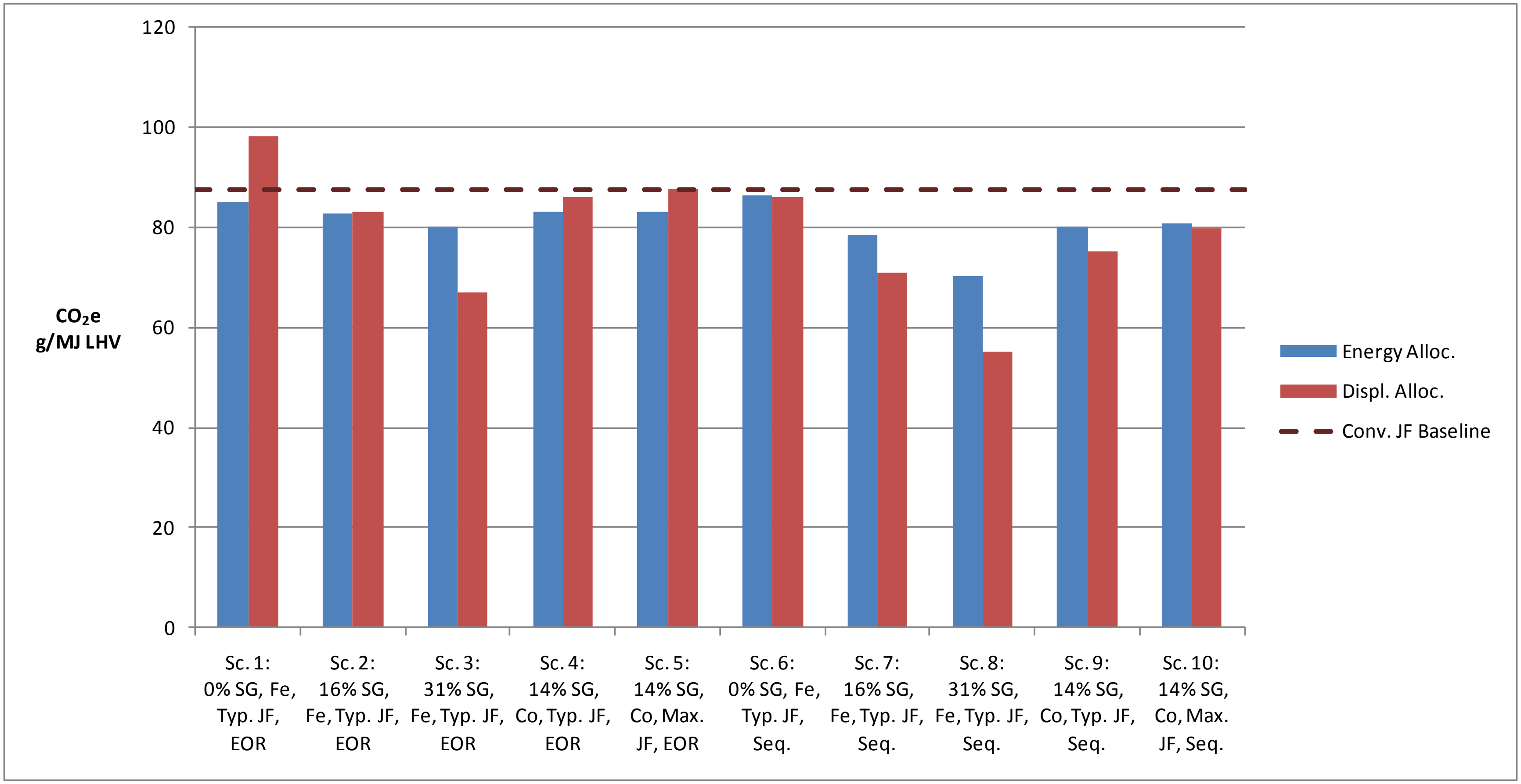


Figure 101. Allocated CO_2e Emissions for 10 Scenarios (g CO_2e/ MJ, LHV [IPCC 2007 100-year GWP])

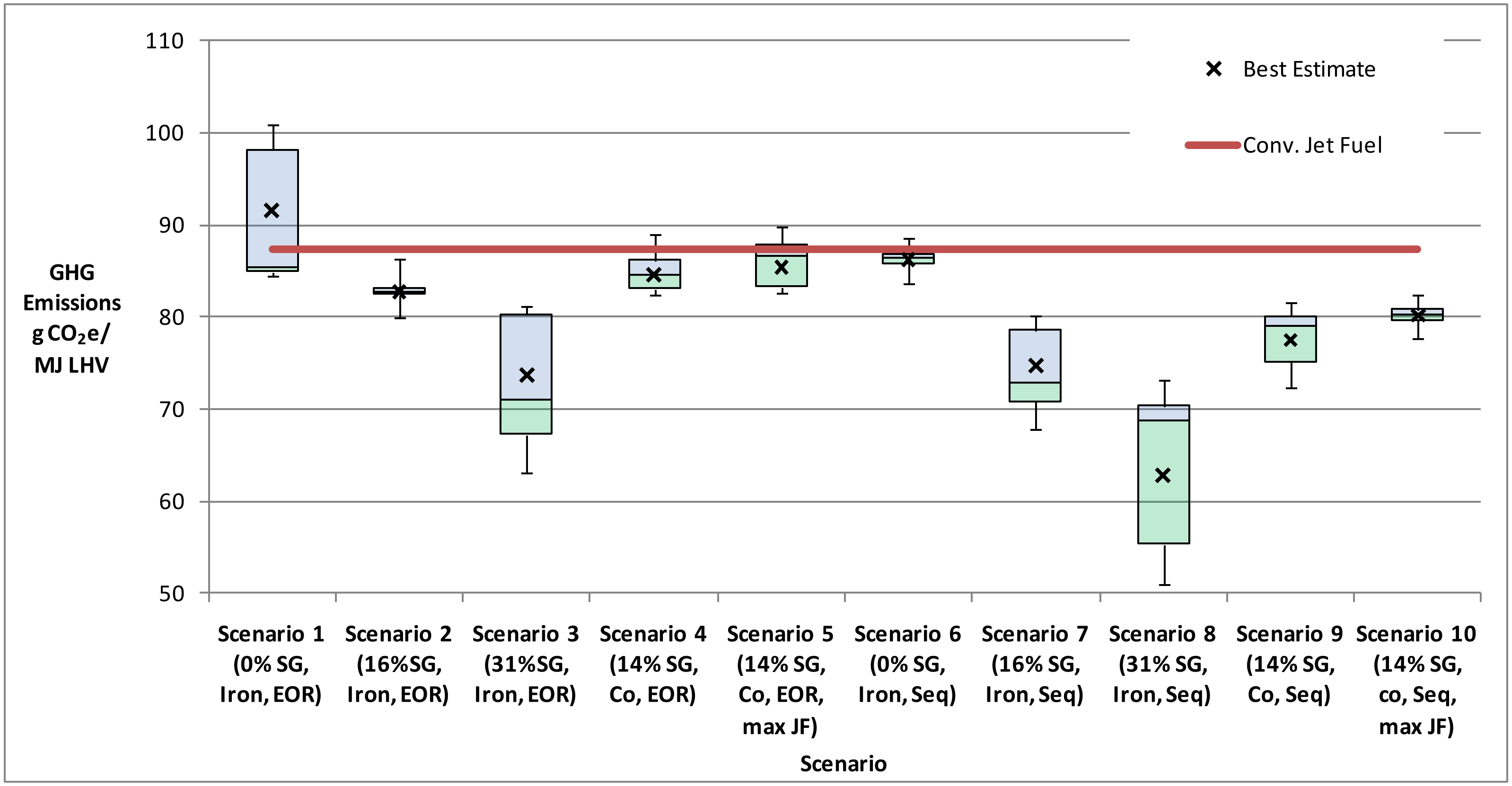


Figure 102. Uncertainty in CO_2e Emissions (Using IPCC 2007 GWP) for All Scenarios Using Combined Result

significance of combustion emissions in the lifecycle. The consequence of this result is that, common to other fuel production lifecycles, improvements to efficiency and emissions of the fueled aircraft are the largest potential driver of reductions to the GHG footprint of the fuel.

Operation processes represent approximately 99 percent of lifecycle emissions when allocation has been applied, for each scenario. The GHG significance of capital equipment is muted by other factors in the lifecycle.

Scenario 8, which uses 31 percent biomass (highest switchgrass portion of all scenarios) and sequestration of supercritical CO_2, has the lowest GHG profile of all modeled scenarios throughout all allocation results. The combination of the GHG sink from switchgrass and the low emissions of CO_2 sequestration relative to EOR produces the most competitive blended jet fuel option in terms of GHG emissions.

Finally, Scenarios 5 and 10 maximize jet fuel output from the CBTL facility. The results show that while this action reduces direct emissions from the liquid fuel facility per unit jet fuel output, the significance of the achievement is far outweighed by other lifecycle choices.

11.2 Modeling Choices and Parameters that Substantially Affect Results

Of the many modeling choices and parameters that were included in this study, the following were found to have the most profound effect on study results.

11.2.1 Coal Bed Methane

One important aspect of this analysis is the assertion that maintaining coal bed methane emissions below a specific threshold is critical to the viability of an F-T jet fuels production process that relies on a coal or coal plus biomass. As discussed in detail in **Section 4.1**, the amount of coal bed methane produced is highly variable—both among different mines within a region, and within different segments or operating conditions of a single mine. CBM emissions from gassy mines are reasonably well documented by US EPA. Therefore, because CBM emissions are a significant life cycle contributor to GHG emissions, the choice of a specific mine for supply of coal to the CBTL process is expected to be critical to a given facility's ability to meet federal LC GHG emissions standards.

Sourcing coal from a mine not considered gassy under US EPA's standards, or on the lower end of gassy mines, would therefore be required. Such a requirement could potentially inform the location of a proposed CBTL facility, in order to enable viable supply lines from mines with low CBM emissions. As noted in **Section 4.1**, the 150 scf/ton CBM emission factor is sufficiently low to meet LC GHG targets only with the implementation of a 40 percent CBM capture rate for Scenarios 1 and 6. While CBM capture is anticipated to be viable within many mining operations, it is not likely to be implementable under all situations. For instance, for some mining operations, CBM capture may be too costly to implement, or successful implementation may be allayed due to specific engineering considerations. Alternatively, for mines that do not presently have CBM capture facilities, in order to maintain coal sourcing contracts with a proposed CBTL facility, such mines might be required, as a contract condition, to implement and maintain CBM capture systems, in order to meet a specified target CBM emission factor.

11.2.2 Carbon Capture Rate

As discussed in **Section 6.1**, the study assumes a 91 percent CO_2 capture rate, with sensitivity values ranging from 90 percent to 92 percent. Although this percentage change is small, the range of CO_2e emissions that occur as a result of this fluctuation range from 659 to 811 g CO_2e/kg F-T jet fuel, for LC Stage #3a. This is equivalent to a 10.3 percent decrease or increase, in comparison with the deterministic emission value of 735 g CO_2e/kg F-T jet fuel under Scenario 2. Discussions with internal experts at NETL indicate that higher carbon capture rates may be technologically and economically feasible—as high as 95 percent or 96 percent. However, due to the developing nature of such technologies, there remains reasonable uncertainty regarding its eventual effectiveness, applicability, and cost when applied at commercial scale under daily operational conditions.

Regardless of the maturity of carbon capture technologies, it is clear that LC Stage #3a emissions are strongly sensitive to variation in CO_2 capture rate at the CBTL facility. Therefore, when considering real world project design for a facility similar to those assessed within this study, the ability of an operating plant to consistently meet or exceed CO_2 capture design standards will be critical to its ability to meet lifecycle GHG emissions targets.

11.2.3 Carbon Management Strategy

Within this study, two options for carbon management are evaluated: capture and use of CO_2 for EOR, and capture and injection of CO_2 into a saline geologic formation, for permanent geologic sequestration. Under both carbon management strategies, CO_2 losses are expected to occur during CO_2 pipeline transport, and potentially following injection into underground oil-bearing or non oil-bearing formations. In addition to fugitive emissions, EOR results in the production of additional fossil fuels, which carry additional carbon that could eventually be emitted to the atmosphere. As discussed previously, emissions from fossil fuels produced via EOR are accounted for in light of the allocation strategies applied to each scenario.

Strictly in terms of the results of this study, Figure 101 and Figure 102 provide an easy means of comparison among EOR scenarios and sequestration scenarios. As shown, geologic sequestration results in consistently lower lifecycle GHG emissions, as compared with EOR. For instance, comparing the Scenario 2 to its sequestration analogue (Scenario 7) shows that best estimate lifecycle CO_2e emissions values are 8.0 g CO_2e/MJ LHV lower for the sequestration scenario than for the baseline scenario. Comparing Scenario 3 to Scenario 8 (both 31 percent switchgrass) provides the most substantial difference, with sequestration Scenario 8 having a best estimate lifecycle GHG emissions value that is 21.8 g CO_2e/MJ LHV lower than its EOR analogue.

These results also underscore an interesting potential trade-off between project economics and sequestration rate. Carbon dioxide, when sold for use in EOR, could represent an additional revenue stream for a given CBTL operator. However, unless more stringent GHG emissions limits are passed, no significant additional revenues are anticipated from saline sequestration. Therefore, economic considerations may drive some CBTL operators, in particular those located in areas that could serve EOR operations, to choose EOR as a carbon management strategy, even though it may not be the most effective, from an environmental standpoint.

11.2.4 Biomass Content of CBTL Facility Feedstock

As discussed in **Section 11.1**, the percentage of biomass versus coal feedstock delivered to the CBTL facility resulted in the greatest variability among the 10 modeled scenarios. The highest GHG emissions, for both saline sequestration and EOR carbon management strategies, were for 0 percent biomass (i.e., Scenarios 1 and 6; refer to Figure 101). Interestingly, the proportion of biomass usage is also closely tied to the amount of land area that would be transformed, directly and indirectly, as a result of implementing one of the 10 scenarios. Although direct and indirect land use change represents only a minor portion of total lifecycle GHG emissions for each scenario, the magnitude of change in local or regional farming practices would of course be higher for scenarios using higher percentages of biomass.

In most cases, at least under current market conditions, biomass is more expensive than coal, on a per unit of energy basis. Therefore, while maximizing biomass usage would support lower lifecycle GHG emissions, doing so may not be feasible under real world circumstances. Thus, meeting Air Force requirements for lifecycle GHG emissions from alternative fuels again represents a trade-off between economic considerations and lifecycle emissions benefits.

Of course, switchgrass is not the only available form of biomass that could be used in support of the production of CBTL jet fuels. Other sources may include short rotation woody crops, corn stover, or waste biomass sources, and a combination of different biomass sources may be feasible. Waste biomass sources, such as wood waste or agricultural waste, may in particular provide benefit to alternative fuels production, since they may in some cases be less expensive than dedicated biomass production.

11.2.5 Allocations Methods

As illustrated in Figure 101 for Scenario 1, the choice of allocation method used for evaluation under this study was important enough to drive at least one final result above or below the conventional jet fuel baseline lifecycle GHG emissions values. Such a result could potentially trap practioners into choosing the allocation method which minimizes the CO_2e for F-T jet fuel ex ante—after the results are known—rather than choosing the method that minimizes uncertainty or enhances comparability.

Comparing the two methods of allocation shown in Figure 101, energy and displacement, it is clear that the displacement allocation method results in increased variability among scenarios with variable amounts of biomass, as compared to energy allocation. Herein, displacement allocation results in the application of what is effectively a larger displacement credit for systems that utilize higher proportions of biomass. Conversely, the displacement credit for coal-only systems (i.e., Scenarios 1 and 6) is proportionally reduced. Additionally, the substitutive value of petroleum naphtha within this study is uncertain. Therefore, for investigations or scenarios where higher naphtha production rates are considered, the use of an energy-based allocation strategy may be preferable.

11.3 Modeling Choices and Parameters that Minimally Affect Results

The following modeling choices and parameters were included in the study to examine their potential impact on study outcomes. However, these modeling choices and parameters were found to have only minimal effects on study results.

11.3.1 F-T Catalyst Choice

This study included evaluation of both iron and cobalt F-T catalysts, as well as variations in the F-T process associated with the use of either catalyst. Comparing Scenario 2 (baseline, iron catalyst, 16 percent switchgrass) and its analogue Scenario 4 (cobalt catalyst, 14 percent switchgrass) shows relatively little variation in terms of the best estimate value (see Figure 102). Specifically, best estimate emissions under Scenario 2 are 82.8 g CO_2e/MJ LHV, versus 84.6 g CO_2e/MJ LHV for Scenario 4. This is equivalent to a 2.1 percent higher emissions rate for the cobalt F-T catalyst scenario, as compared to the iron catalyst scenario, and at least 90 percent of the difference in GHG emissions between these two scenarios results from the disparity in switchgrass feed rate between the two scenarios, rather than the catalyst choice.

11.3.2 Switchgrass Harvesting Practices

Switchgrass harvesting practices evaluated within this study include the use of rectangular or round bales, and varying methods of bale storage. Switchgrass harvesting practices were initially considered because it was thought that, in particular, the mode of storage could substantially influence the degradation rate and/or water content of the switchgrass, as it was delivered to the CBTL facility. However, no substantial change in stagewise or life cycle GHG emissions was indicated as a result of differences in switchgrass harvesting practices.

11.3.3 Construction of Facilities and Equipment

Many pieces of equipment and many different facilities, including farm equipment, the CBTL facility, transport trucks, pipelines, and various other facilities are constructed within the boundary of this study. However, for all LC stages, emissions associated with facility construction represented less than 0.2 percent of total stagewise emissions. The highest emissions rates, in terms of a proportion of total stagewise emissions, were from construction of the EOR facility (0.18 percent of total LC Stage #3c emissions), construction of the CBTL facility (0.17 percent of total LC Stage #3a emissions), and construction of the CO_2 transport pipeline (0.16 percent of total LC Stage #3b emissions). For all other LC stages, construction-related emissions accounted for less than 0.10 percent of total emissions.

11.3.4 Transport Options for Finished Fuels

This study included evaluation of two separate options for the transport of finished fuels: transport to a single airport, Chicago O'Hare airport, via a dedicated pipeline, or transport to Chicago O'Hare airport along a pipeline plus additional tanker truck transport from a centralized fuel terminal to smaller regional airports. As discussed in **Section 7.3**, these options resulted in only a very minor difference in the total amount of carbon dioxide emissions under LC Stage #4c.

11.4 Other Conclusions

The following additional considerations relate to the scope of the study, including the number of individual scenarios that were run, as well as the level of effort warranted for examination of a single proposed facility, as compared to the level of effort that was implemented in support of this study.

11.4.1 Number of Scenarios

This case study includes evaluations for ten distinct scenarios, each having additional operational options related to switchgrass baling (three options) and blended jet fuel transport (two additional options). This relatively high level of detail was chosen by the IAWG in order to help evaluate which life cycle aspects and parameters are the most important and critical, and which are less important and less critical, in terms of their effect on life cycle GHG emissions. As discussed previously, study scenarios pertaining to carbon management, such as CO_2 capture rate, proportion of biomass used for feedstock to the CBTL facility, and EOR or sequestration as carbon management strategies, were found to have substantial bearing on life cycle GHG emissions results. Conversely, study options such as the type of F-T catalyst, switchgrass harvesting and baling practices, construction of facilities and equipment, and transportation modes for finished fuels, all had relatively little bearing on lifecycle outcomes.

It is anticipated that future LCA studies conducted in support of a specific or proposed F-T jet fuel production process would require a substantially reduced level of effort, in comparison to this study. For instance, fewer scenarios would likely be evaluated, and low priority options, such as finished fuels transportation mode or biomass harvesting and baling options, would not likely be considered.

11.4.2 Alternative Biomass Feedstocks

The present study evaluates the GHG burdens of producing F-T jet fuel from varying combinations of coal and biomass. Only switchgrass biomass is considered; however, various other types of biomass could potentially be employed in support of F-T jet fuels production. While the present analysis provides a reasonable level of detail with respect to fuel production using switchgrass biomass, the analysis does not evaluate potential environmental flows associated with other types of biomass production and delivery. Other biomass types may vary considerably in their comparative energy and GHG burdens. For instance, depending upon how LC Stage #1 flows are allocated, the use of residual/waste biomass in place of a dedicated switchgrass crop could reduce GHG and energy use under LC Stage #1b. Therefore, for subsequent case studies considering non-switchgrass biomass feedstocks, additional evaluation and analysis of biomass production (LC Stage #1b) and transport (LC Stage #2b) is warranted.

11.4.3 Level of Effort

As a first case study under the Framework and Guidance Document, this study represents a significant level of effort, produced by the collaborative efforts of over 20 IAWG participants. As a result, this report provides a relatively high level of detail in assessing 10 F-T jet fuel scenarios, along with an additional 5 modeling options, and a suite of sensitivity parameters. Subsequent lifecycle analyses implemented by CBTL facility project proponents are expected to be much abbreviated in scope, and would likely evaluate a much smaller number of scenarios and modeling options. Also, much of the work in regards to data collection and model building

completed for this analysis is expected to be relevant to and usable for future analyses, thereby substantially reducing level of effort.

11.5 Most Competitive Options

The most competitive options identified within this study, when focusing solely on the minimization of life cycle GHG emissions, are those options represented by Scenarios 3 and 8—that is, 31 percent switchgrass, iron catalyst, and either EOR or, preferably, saline sequestration as a carbon management strategy. However, the competitiveness of all options would be significantly informed by costs, siting, and feasibility issues, which are expected to vary widely from project to project. In-depth consideration of these additional parameters is beyond the scope of this LCA.

12.0 CASE STUDY ASSESSMENT AND RECOMMENDATIONS

As discussed in **Section 2**, one purpose of this case study was to test the LCA methods set forth in the Framework and Guidance Document. This section provides a discussion of insights obtained from the application of this case study, and suggests revisions to the Framework and Guidance Document. The following list summarizes areas of improvement and clarification recommended for consideration in the next revision the Framework and Guidance Document.

- **Add guidance on documenting methodology limitations and uncertainty that cannot be quantitatively documented.** Inherent within the purpose of this guidance is a conflict between the system boundary for the conventional petroleum baseline and the alternative to be compared. The conventional petroleum baseline is an attributional life cycle assessment that characterizes the average 2005 emissions profile, a one-year temporal period for the system boundary. This modeling assumption was specified within the EISA 2007 legislation. In contrast, the alternative jet fuel process, including construction and operation, is modeled on a 30-year temporal basis to assess the global warming potential throughout its "life cycle." The inherent difference in temporal period between the conventional petroleum baseline and the alternative jet fuel process creates an unquantified level of uncertainty that is not captured in the comparative analysis.
- While attempts are made to stay out of the realm of consequential LCA, inevitably assumptions made about systems 30 years in the future require decisions about how the system will function. Examples include the availability of biomass and coal from the locations proposed by the alternative, the efficiency of the F-T process, state of knowledge on modeling direct and indirect land use impacts, and future product and co-product markets. The lack of precision in predicting how a system will be operated in the future given external factors is another example of added uncertainty that is not reflected in the conventional petroleum baseline. These factors should be noted as data limitations and reported with the study results to inform decision makers of the inherent levels of uncertainty and modeling difference not captured within the Framework and Guidance Document.
- **Reduce the level of effort and/or approach required to document Data Quality Indicator scores.** The approach outlined in the Framework and Guidance Document for documenting data quality using the Data Quality Indicator scoring system was noted as having two challenges: (1) some of the scoring categories are too broad and/or subjective, leading to differences in scoring among LCA practitioners, and (2) the level of effort required to perform the DQI scoring did not translate into significant insights or value compared to the knowledge of the practitioner in identifying areas for improvement. Therefore, it is recommended that the DQI scoring system be evaluated to balance value-added benefits with the level of effort required to implement the process. Caution is warranted to ensure a mechanism that systematically forces the practitioner to evaluate data quality and document limitations/areas for improvement, is not removed from the guidance document.

- **Clarify/restate in the data quality section of the Framework and Guidance Document that high quality data (data that score a 1 or 2) should not use a default +/- 10 percent uncertainty bound when better or actual stochastic properties are known.** The Framework and Guidance Document states that a +/- 10 percent uncertainty range should be applied to high quality data. However, a +/- 10 percent uncertainty range may not be appropriate (i.e., conservative) in some situations. The section needs to clarify that this default range should only be applied when no other uncertainty information is known. The default uncertainty range was provided to reduce the effort on the part of the practitioner in developing defensible uncertainty information for data perceived to be of acceptable quality. In performing the study, it was noted by the practitioners that the actual amount of uncertainty data available was very limited, and in most cases professional judgment or basic engineering calculations were used to bound conservative ranges. The level of effort required was not excessive, and viewed to provide greater value than applying a default range. This modified approach also reduces potential for the inappropriate use of a +/- 10 percent default range, in inappropriate situations.
- **Better define the scope of a "unit process" when applying the** greater than 0.1 CO_2e/MJ limit to determine significance. A "unit process" could be defined by different practitioners at different levels of depth. For example, using the delivery of coal to the energy conversion facility, one may purchase or acquire a life cycle profile for the production and delivery of coal to the end user, and view that profile as a "unit process." A second practitioner may evaluate delivery of coal to the energy conversion facility in a substantially different manner. For instance, the second practitioner might develop numerous smaller modeling blocks that comprise coal production and delivery (e.g., coal mine conveyer, crusher, coal transport, etc.) and determine the smallest unit of characterization to meet the definition of a "unit process" within the Framework and Guidance Document. In general, the definition was meant to imply the smallest (foundation) modeling unit within a study (i.e., no compounding or aggregation of one or more modeling blocks). Therefore, it is recommended that the definition of "unit process" be evaluated and clarified with respect to the determination of significance rule within the guidance document.
- **Add guidance on reporting and interpreting study results.** The current Framework and Guidance Document explains how to conduct the assessment but is absent on how to report the results in terms of key elements, level of detail, and documentation of data limitations. Therefore, it is recommended that additional guidance on reporting and interpreting study results be added to the guidance document.
- **Consider recommending a preferred or default co-product allocation method for evaluating alternative jet fuel options.** The current Framework and Guidance Document provides a clear methodology for identifying potential co-product allocation options that may be considered appropriate. Within the practice of life cycle assessment, it is common for the practitioner conducting the study to select the preferred co-product allocation method and apply it to the study results. Alternative co-product allocation methods are then applied and documented in the context of a sensitivity or uncertainty analysis. The current guidance document views alternative co-product allocation methods as forms of modeling uncertainty and reports the results as a combination of the various co-product allocation methods. Depending on a practitioner's attention

to/consideration of alternative methods, applications of this methodology by one or more practitioners could result in different representations of the uncertainty within the results, by applying a diverse range of co-product allocation methods. Therefore, it is recommended that the guidance document provide additional guidance on selecting a preferred allocation procedure, when more than one method may be viewed as appropriate. This will improve comparison of multiple alternatives by the decision maker and form a reasonable basis of understanding when interpreting results for alternative jet fuel options. The reporting of results using a default allocation method, such as energy allocation, should not replace the reporting of multiple co-product allocation procedures that are deemed feasible as forms of model uncertainty, in accordance with the current Framework and Guidance Document.

- **Reasonable levels of documentation and reporting should be evaluated for application of the Framework and Guidance Document.** The current report contains 10 alternative jet fuel production scenarios. Application of this methodology in practice would only consider one alternative jet fuel production method. The physical length of this report has been noted by the authors as a restriction to applying the approach and also that attention to transparency and precision led to a voluminous report necessary for quality assurance and external peer review. However, a reduced form more appropriate for a decision maker to interpret summary results should be considered. Therefore, it is recommended that additional guidance be added to the guidance document, in regards to level of documentation for external peer review, and guidelines for providing summaries of key findings for decision makers.

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APPENDIX A

CALCULATING THE F-T JET FUEL PRODUCT PORTION FROM AN IRON CATALYST CBTL PROCESS

A life-cycle assessment of the greenhouse gas (GHG) emissions of diesel produced from a Coal and Biomass to Liquids (CBTL) process using an iron-catalyst Fischer-Tropsch (F-T) column is provided in *Affordable, Low-Carbon Diesel Fuel from Domestic Coal and Biomass* (Tarka, 2009). The products in that analysis are naphtha and diesel, with no F-T jet fuel cut. In order to compare the results of another CBTL analysis with a cobalt-catalyst F-T reactor (Allen et al, 2010), the amount of F-T jet fuel produced in the iron-catalyst case was needed. This Appendix describes how the amount of F-T jet fuel produced in the iron-catalyst case was calculated.

In order to find the portion of naphtha and diesel that could be considered to be F-T jet fuel, knowledge of the composition of the streams is needed. F-T jet fuel must meet military specs for a range of distillation cuts. In a personal communication, Tarka (2010a) provided a carbon number distribution for the output of the F-T column. This carbon number distribution could be related to the modeled output for Case 7 of the report in a separately provided personal communication (Tarka, 2010a).

To determine which products to place in the F-T jet fuel cut, a group contribution method was used to estimate the boiling points for components in the stream (Allen, et al., 2010). There are two streams from the iron catalyst F-T column that must be separated into appropriate product fractions. One is a stream of long-chain hydrocarbons (wax) that is fed to a hydrocracker, producing fuel gas, naphtha, F-T jet fuel blendstock, and diesel. The other stream is a straight run liquid stream containing compounds in the naphtha to diesel range.

Determining the amount of F-T jet fuel in the straight run products (C5-C18) from the F-T reactor was straightforward. The beginning and ending boiling point values were selected so that after mixing with the F-T jet fuel blendstock stream from the hydrocracker products, the overall stream meets the military specifications for F-T jet fuel that can be blended with jet fuel from conventional refineries in order to make an aviation fuel that meets military specifications (DoD, 2008), as shown in the table below.

Table A-1. F-T Jet Fuel from Straight Run Product Stream of Iron-Catalyst F-T Reactor

Boiling Point, (Degrees C)	% of Straight Run Products	Cumulative % of F-T Jet Fuel Portion of Straight Run Products	Milspec
230-296	48.0	100.0%	Must be at least 90%
206-229	13.3	51.3%	Must be at least 50%
184-205	13.6	37.8%	Must be at least 10%
169-183	7.2	24.0%	Must be less than 90%
158-168	7.3	16.8%	Must be less than 50%
130-157	9.3	9.4%	Must be less than 10%

Of the straight run products, 98.6 percent are F-T jet fuel, 0.5 percent are naphtha, and 1 percent are diesel. The total straight run flow rate is 37,200 lb/hr, so the naphtha flow rate is 176 lb/hr, the F-T jet fuel flow rate is 36,600 lb/hr, and the diesel flow rate is 358 lb/hr.

The carbon number distribution of the diesel and naphtha output of the hydrocracker was not provided and had to be estimated. All that is known about the wax is that it is 3.2 wt percent C19-C24 and the remainder C25+. By carbon number mass fraction, the component distribution

of a number of F-T reactor waxes (Shah et al, 1988) has been observed to fit a log normal distribution. For the baseline case of this study, a component distribution with μ of 3.51 and σ of 0.17 was used because with this distribution, the sum of the weight percentages for C19-C24 is 3.3 percent wt %, nearly matching the given information about wax composition. The modeled wax ranges from C19-C72, with a maximum in the C32-C33 range. A distribution of products from this modeled wax after feeding to a hydrocracker was developed using the hydrocracker model described in Allen et al, 2010. While this hydrocracker model is known to underestimate the production of fuel gas, the modeled distribution compares favorably to the distribution of the products reported from the hydrocracker by Tarka in a personal communication (2010a,b), as shown in Figure A-1.

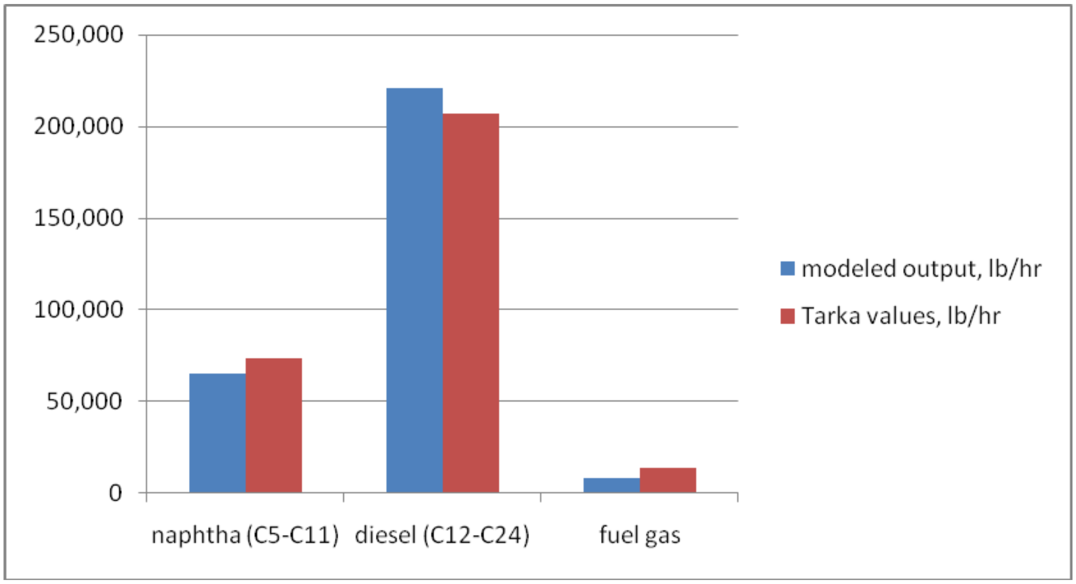

Figure A-1. Modeled Output and Tarke Value for Naphtha, Diesel, and Fuel Gas

Note that the fuel gas, naphtha, and diesel cuts reported by Tarka (2010a,b) were grouped by carbon number, not boiling point. For the purposes of comparison, the values in the figure above are reported based on carbon number for both the modeled case and from Tarka (2009, 2010a,b).

The beginning and ending cuts of the modeled F-T jet fuel stream from the hydrocracker were selected so that the F-T jet fuel stream meets the military specifications for distillation cuts. The stream exhibits the following profile:

Table A-2. F-T Jet from Hydrocracker Product Stream for Iron-Catalyst F-T Reactor

Boiling Point, (Degrees C)	% of Hydrocracker Output	Cumulative % of F-T Jet Fuel Portion of Hydrocracker Output	Milspec
263-267	3.2	N/A	N/A
230-262	14.1	92.9%	Must be at least 90%
206-229	7.7	61.8%	Must be at least 50%
184-205	8.0	45.0%	Must be at least 10%
169-183	3.6	27.4%	Must be less than 90%
158-168	4.5	19.5%	Must be less than 50%
130-157	4.4	9.6%	Must be less than 10%

The modeled hydrocracker products are 2.8% fuel gas, 10.8% naphtha, 45.5% F-T jet fuel, and 40.9% diesel (mass basis). Because production of fuel gas is underestimated by the model, it is recommended that Tarka's (2009, 2010a,b) value for fuel gas production be used and the remaining products apportioned according to the modeled values. The total output of the hydrocracker is 295,000 lb/hr, so the output of products from the hydrocracker when F-T jet fuel is included as a product is 14,100 lb/hr fuel gas, 31,100 lb/hr naphtha, 132,000 lb/hr jet fuel, and 118,000 lb/hr diesel. The combined flow rates of straight run product from the F-T reactor and upgraded wax from the F-T reactor are given below.

Table A-3. Combined Flow Rates of Straight Run Product and Upgraded Wax from the F-T Reactor

Stream	Straight Run Output (lb/hr)	Upgraded Wax Output (lb/hr)	Total (lb/hr)
Fuel Gas	N/A	14,099	14,099
Naphtha	176	31,119	31,295
F-T Jet Fuel	36,638	131,593	168,232
Diesel	358	118,224	118,582
TOTAL:	37,172	295,035	332,207

Densities of these streams were estimated using a weighted average of the densities of individual compounds. The estimates are 0.676 mg/L, 0.751 mg/L, and 0.784 for the naphtha, F-T jet fuel blendstock, and diesel streams, respectively

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APPENDIX B

ENERGY CONTENT AND COMBUSTION EMISSIONS OF F-T CBTL FUELS

The heats of combustion for the diesel and F-T jet fuel streams (see main report) were estimated based on group contribution methods developed by the Department of Transportation/Federal Aviation Administration (DOT/FAA, 2001). This report provides group contributions for the heats of combustion (higher heating value) for each of the three functional groups in diesel and F-T jet fuel made from upgraded wax:

- $-CH_3$ 775 kJ/mol
- $-CH_2-$ 670 kJ/mol
- -CH< 518 kJ/mol

In the iron catalyst case, the liquid stream from the F-T reactor is largely in the F-T jet fuel range, but contains many olefinic compounds. It was assumed that these alkenes were straight chain with one olefinic bond per molecule. The group contribution of the higher heating value of this structural group (>C=C<) is 781 kJ/mol, and the group contribution for the higher heating value of a hydrogen bound to another atom is (DOT/FAA, 2001):

-H 190 kJ/mol

LHVs were calculated using the following relationship (DOT/FAA, 1998):

$$\text{LHV (kJ/g)} = \text{HHV (kJ/g)} - 21.96 \text{ (weight fraction hydrogen)}$$

The LHV of the iron catalyst case F-T jet fuel was estimated to be 44.7 MJ/kg and its carbon fraction is 0.850. If all the carbon in this F-T jet fuel is converted to CO_2 during combustion, the GHG emissions on an energy basis are:

$$\text{(0.850 kg carbon/kg F-T jet fuel)} \times \text{(44 kg CO}_2\text{/12 kg C) / (44.67 MJ/kgF-T jet fuel)} = 69.8 \text{ g CO}_2\text{/MJ.}$$

For the 14 percent switchgrass, cobalt F-T catalyst case where diesel is a co-product, this value is:

$$\text{(0.848 kg carbon/kg F-T jet fuel)} \times \text{(44 kg CO}_2\text{/12 kg C)/(44.80 MJ/kg F-T jet fuel)} = 69.4 \text{ g CO}_2\text{/MJ,}$$

and for the 14 percent switchgrass, cobalt F-T catalyst case where production of F-T jet fuel is maximized, this value is:

$$\text{(0.848 kg carbon/kg F-T jet fuel)} \times \text{(44 kg CO}_2\text{/12 kg C) / (44.74 MJ/kg F-T jet fuel)} = 69.5 \text{ g CO}_2\text{/MJ,}$$

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APPENDIX C

LIFE CYCLE EMISSIONS RESULTS FOR THE MODIFIED BASELINE SYSTEM BOUNDARY

The following explains an alternative approach to defining the system boundary for this study by considering the carbon dioxide produced at the F-T plant as a co-product applicable to co-product allocation with the jet fuel, diesel, fuel, and naphtha produced at the F-T plant. This alternative system boundary differs from that used within the main report by not expanding the boundary to include the carbon management strategy employed. As a result, the modified system boundary approach and results outlined below would be applicable if the disposition of the carbon dioxide produced at the F-T plant was unknown; i.e., sold into an open CO_2 market.

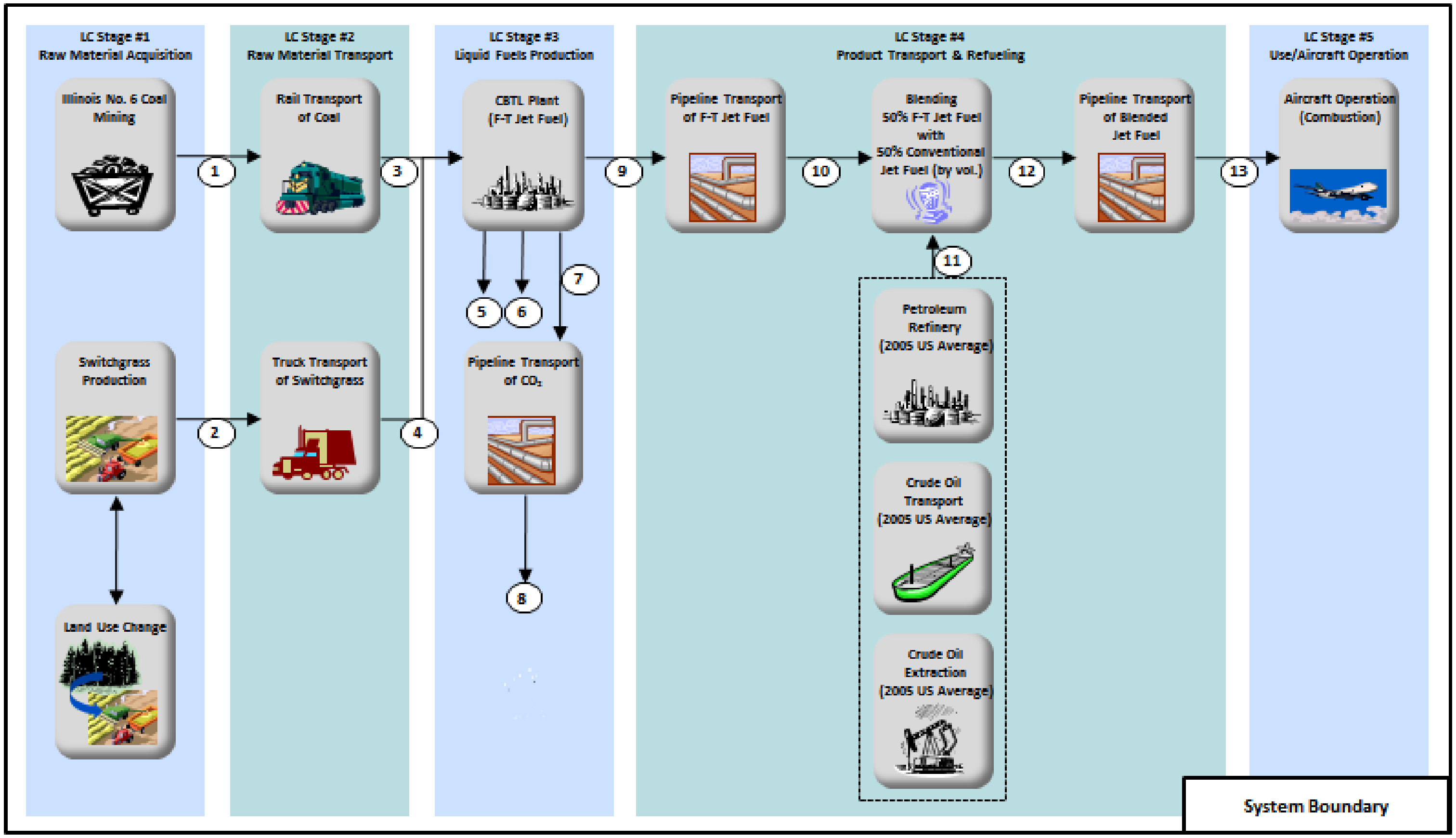
C.1 Introduction

As discussed in **Section 3** of the main body of this report (main report), two system boundaries were considered within this study. The main report describes modeling procedures, flows, emissions, allocation procedures, sensitivity analysis, uncertainty analysis, and other items as relevant to the baseline system boundary. GHG emissions for the modified baseline system boundary are not disclosed in the main body of this report. The purpose of this appendix is to report lifecycle GHG emissions that were modeled under the modified baseline system boundary.

C.2 Purpose and Description of the Modified Baseline System Boundary

The modified baseline system boundary was incorporated into the F-T Jet Fuel Spreadsheet Model in order to evaluate an alternative co-product allocation scenario. Under the modified baseline system boundary, supercritical carbon dioxide (CO_2) produced by the CBTL facility (LC Stage #3a) is assumed to enter CO_2 commodities market for enhanced oil recovery (EOR), where it would displace naturally-sourced (i.e., mined) CO_2. More specifically, the cut-off point for the modified baseline system boundary is at the point where supercritical CO_2 enters the EOR facility under the baseline system boundary. But within the modified baseline system boundary, EOR is not considered as an explicit activity, and the co-products that result from EOR operations under the baseline system boundary do not occur under the modified baseline system boundary. For the purposes of this analysis, the point where supercritical CO_2 leaves the end of the CO_2 conveyance pipeline is termed the "CO_2 delivery point." The supercritical CO_2 is assumed to enter the CO_2 commodities market for EOR, so that this CO_2 can be assumed to be sequestered in an aquifer at the conclusion of EOR. In a general commodities market for CO_2, the CO_2 could be used for a purpose that does not result in the sequestration of the CO_2 in an aquifer. All other aspects of the modified baseline system boundary are the same as the baseline system boundary, as described in the main report.

The CO_2 delivery point applies only to the modified baseline system boundary for Scenarios 1-5, which include CO_2-EOR as a carbon management strategy. For Scenarios 6-10, sequestration of CO_2 in a saline geologic formation is used as the carbon management strategy, exactly as it is for the baseline system boundary, and as described in the main report. Figure C-1 provides an illustration of the modified baseline system boundary for Scenarios 1-5, while Figure 7 of the main report provides an illustration of the system boundary for Scenarios 6-10.



No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units	No.	Reference Flow	Value	Units
1	Illinois No. 6 Coal (AR)	n/a	g/MJ LHV	6	F-T Naphtha	n/a	g/MJ LHV	11	Conv. Jet Fuel	n/a	g/MJ LHV
2	Switchgrass	n/a	g/MJ LHV	7	Supercritical CO_2	n/a	g/MJ LHV	12	Blended Jet Fuel	n/a	g/MJ LHV
3	Illinois No. 6 Coal (AR)	n/a	g/MJ LHV	8	Supercritical CO_2	n/a	g/MJ LHV	13	Blended Jet Fuel	n/a	MJ, LHV
4	Switchgrass	n/a	g/MJ LHV	9	F-T Jet Fuel	n/a	g/MJ LHV	14			
5	F-T Diesel	n/a	g/MJ LHV	10	F-T Jet Fuel	n/a	g/MJ LHV	15			

Figure C-1. Modified Baseline System Boundary for Scenarios 1-5 (CO_2 Co-Product)

For Scenarios 1-5, there are four co-products: F-T jet fuel, F-T diesel, F-T naphtha, and supercritical CO_2. These co-products differ from those in the baseline system boundary (which include crude oil and natural gas liquids from EOR and exclude super critical CO_2). For Scenarios 6-10, there are three co-products: F-T jet fuel, F-T diesel, and F-T naphtha. These co-products are the same as those in the baseline system boundary.

C.3 Unallocated Inputs, Outputs, and GHG Emissions

This section presents the major input and output flows to the modified baseline system boundary for the 10 scenarios. The section also discusses the unallocated GHG emissions for the system.

C.3.1 Unallocated Input and Output Flows

The boundary for Scenarios 1-5, those where captured supercritical CO_2 is transported to the CO_2 delivery point just before the EOR operations, is shown in Figure C-1. The boundary for Scenarios 6-10 includes CO_2 sequestration in a saline formation, and is the same under the modified baseline system boundary as compared to the baseline system boundary. It is represented in Figure 7 of the main report.

Table C-1 provides the value for each major input and output flow for Scenarios 1-10 using the flow numbers in Figure C-1. The flows in Table C-1 are relative to the functional unit of 1 MJ LHV of jet fuel combusted. Table C-2 provides these same flows expressed as mass consumed or produced each day. While Scenarios 1-5 of the modified baseline system boundary do not consider EOR as a carbon management strategy and associated input and output flows, all other input and output flows are the same as for the baseline system boundary. Therefore, the discussion of input and output flows provided in the main report also applies to the modified baseline system boundary, and the reader is referred thereto.

C.3.2 Unallocated Input and Output Flows

Unallocated emissions of GHGs (CO_2, methane [CH_4], and nitrogen oxice [N_2O]) were calculated for each scenario and GWP from the IPCC 1996, 2001, and 2007 reports were applied to calculate carbon dioxide equivalent (CO_2e) emissions. For each stage, these emissions were calculated relative to the reference flow and relative to the system functional unit. The CO_2e emissions for each stage relative to the functional unit were summed to determine the total unallocated CO_2e emissions for each scenario.

These total emissions relative to the system functional unit represent the total CO_2e emissions for all stages (as g CO_2e) divided by the total energy content of blended jet fuel (as million joules lower heating value [MJ LHV]) for each scenario. The emissions are expressed in terms of the energy content of jet fuel, but the emissions are for up to four co-products: blended jet fuel (a combination of F-T jet fuel and conventional jet fuel), F-T diesel, F-T naphtha, and super critical carbon dioxide. In other words, while the emissions are expressed in terms of the energy content of blended jet fuel, the emissions are unallocated. Until the emissions are allocated among the co-products according to some method, the GHG emissions cannot be interpreted. The unallocated emissions are presented later in this appendix along with the emissions allocated to jet fuel.

Table C-1. Unallocated Major Input and Output Flows Relative to the Functional Unit, Modified Baseline System Boundary

Scenario	Scenario 2 (Baseline)	Scenario 1	Scenario 3	Scenario 4	Scenario 5 (Maximize JF)	Scenario 6	Scenario 7	Scenario 8	Scenario 9	Scenario 10 (Maximize JF)
% Illinois No. 6 Coal	84%	100%	69%	86%	86%	100%	84%	69%	86%	86%
% Switchgrass	16%	0%	31%	14%	14%	0%	16%	31%	14%	14%
F-T Catalyst	Iron	Iron	Iron	Cobalt	Cobalt	Iron	Iron	Iron	Cobalt	Cobalt
Carbon Management Strategy	CO_2 Commodities Market	CO_2 Commodities Market	CO_2 Commodities Market	CO_2 Commodities Market	CO_2 Commodities Market	Seques-tration	Seques-tration	Seques-tration	Seques-tration	Seques-tration
Input or Output Flow	Value (g/ MJ Jet Fuel Combusted, LHV)									
1 Illinois No. 6 Coal (wet)	60	67	52	57	42	67	60	52	57	42
1 Illinois No. 6 Coal (dry)	53	59	46	51	37	59	53	46	51	37
2 Switchgrass (wet)	11	0	24	9.0	6.6	0	11	24	9.0	6.6
2 Switchgrass (dry)	9.4	0	20	7.7	5.6	0	9.5	20	7.7	5.6
3 Illinois No. 6 Coal (wet)	60	67	52	57	42	67	60	52	57	42
3 Illinois No. 6 Coal (dry)	53	59	46	51	37	59	53	46	51	37
4 Switchgrass (wet)	11	0	24	9.0	6.6	0	11	24	9.0	6.6
4 Switchgrass (dry)	9.4	0	20	7.7	5.6	0	9.5	20	7.7	5.6
5 F-T Diesel	7.8	7.8	7.7	5.5	0	7.8	7.8	7.8	5.5	0
6 F-T Naphtha	2	2	2.0	2.5	2.7	2	2	2	2.5	2.7
7 Supercritical CO_2	84	84	84	78	57	84	84	84	78	57
8 Supercritical CO_2 (Seq)	0	0	0	0	0	83	83	83	77	56
8 Supercritical CO_2 (Commodities Market)	83	83	83	77	56	0	0	0	0	0
9 F-T Jet Fuel	11	11	11	11	11	11	11	11	11	11
10 F-T Jet Fuel	11	11	11	11	11	11	11	11	11	11
11 Conv. Jet Fuel	12	12	12	12	12	12	12	12	12	12
12 Blended Jet Fuel	23	23	23	23	23	23	23	23	23	23
13 Blended Jet Fuel	23	23	23	23	23	23	23	23	23	23

Table C-2. Unallocated Major Input and Output Flows on a Daily Basis, Modified Baseline System Boundary

Scenario	Scenario 2 (Baseline)	Scenario 1	Scenario 3	Scenario 4	Scenario 5 (Maximize JF)	Scenario 6	Scenario 7	Scenario 8	Scenario 9	Scenario 10 (Maximize JF)
% Illinois No. 6 Coal	84%	100%	69%	86%	86%	100%	84%	69%	84%	84%
% Switchgrass	16%	0%	31%	14%	14%	0%	16%	31%	14%	14%
F-T Catalyst	Iron	Iron	Iron	Cobalt	Cobalt	Iron	Iron	Iron	Cobalt	Cobalt
Carbon Management Strategy	CO_2 Commodities Market	CO_2 Commodities Market	CO_2 Commodities Market	CO_2 Commodities Market	CO_2 Commodities Market	Seques-tration	Seques-tration	Seques-tration	Seques-tration	Seques-tration
Input or Output Flow	Value (tonne/day)									
1 Illinois No. 6 Coal (wet)	10,000	12,000	9,000	11,000	11,000	12,000	10,000	9,000	11,000	11,000
1 Illinois No. 6 Coal (dry)	9,200	10,000	8,000	9,600	9,500	10,000	9,200	8,000	9,600	9,500
2 Switchgrass (wet)	1,900	0	4,000	1,700	1,700	0	1,900	4,000	1,700	1,700
2 Switchgrass (dry)	1,600	0	3,500	1,500	1,400	0	1,600	3,500	1,500	1,400
3 Illinois No. 6 Coal (wet)	10,000	12,000	9,000	11,000	11,000	12,000	10,000	9,000	11,000	11,000
3 Illinois No. 6 Coal (dry)	9,200	10,000	8,000	9,600	9,500	10,000	9,200	8,000	9,600	9,500
4 Switchgrass (wet)	1,900	0	4,000	1,700	1,700	0	1,900	4,000	1,700	1,700
4 Switchgrass (dry)	1,600	0	3,500	1,500	1,400	0	1,600	3,500	1,500	1,400
5 F-T Diesel	1,300	1,300	1,300	1,000	0	1,300	1,300	1,300	1,000	0
6 F-T Naphtha	350	350	350	470	690	350	350	350	470	690
7 Supercritical CO_2	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
8 Supercritical CO_2 (Seq)	0	0	0	0	0	14,000	14,000	14,000	15,000	15,000
8 Supercritical CO_2 (Commodities Market)	14,000	14,000	14,000	15,000	15,000	0	0	0	0	0
9 F-T Jet Fuel	1,900	1,900	1,900	2,100	2,800	1,900	1,900	1,900	2,100	2,800
10 F-T Jet Fuel	1,900	1,900	1,900	2,100	2,800	1,900	1,900	1,900	2,100	2,800
11 Conv. Jet Fuel	2,000	2,000	2,000	2,200	3,000	2,000	2,000	2,000	2,200	3,000
12 Blended Jet Fuel	3,900	3,900	3,900	4,300	5,900	3,900	3,900	3,900	4,300	5,900
13 Blended Jet Fuel	3,900	3,900	3,900	4,300	5,900	3,900	3,900	3,900	4,300	5,900

C.4 Co-Product Allocation

Co-product allocation was completed based on energy, mass, volume, and displacement. The following text discusses the methods that were used for co-product allocation, as relevant to the analysis completed for the modified baseline system boundary.

C.4.1 Calculation Procedure for Energy, Volume and Mass Allocation

The allocation procedures for energy, volume, and mass were applied to all 10 scenarios. For Scenarios 6-10, the allocation procedures for energy, volume, and mass are the same as for the baseline system boundary because the co-products and system boundary are the same in the modified baseline system boundary and baseline system boundary. For Scenarios 1-5, the allocation procedures for energy, volume, and mass are different for the modified baseline system boundary as compared to the baseline system boundary. The following text explains the energy allocation procedure using Scenario 2 (84 percent coal, 16 percent biomass, iron-based F-T catalyst, CO_2 commodities market) as an example. The energy allocation procedure can readily be modified to perform volume and mass allocation, since all three procedures rely on ratios of a physical property.

Energy allocation is performed in six steps. First, the co-products are defined. For the modified baseline system boundary, there are four co-products produced from the CBTL plant (F-T jet fuel, F-T diesel, F-T naphtha, and super critical CO_2).

Second, the stages involved in the production of the co-products are identified. All the activities in LC Stages #1 through #3 are involved in the production of the four co-products generated in Scenario 2.

Third, the unallocated GHG emissions are summed over the stages involved in the production of the co-products. For Scenario 2, unallocated GHG emissions are summed for the first three stages.

Fourth, super critical CO_2 is a very different product than F-T jet fuel, F-T diesel, or F-T naphtha. The energy density of supercritical CO_2 is very low compared with the energy density of the other F-T co-products, but the mass and volume of super critical CO_2 are much greater than the mass and volume of the other F-T co-products. Thus, allocating GHG emissions to all co-products on the basis of energy will give very different results from allocation based on volume or mass. To avoid this situation, the GHG emissions associated with extracting and transporting naturally occurring CO_2 were calculated and displaced from the total unallocated GHG emissions before allocating the remaining unallocated GHG emissions on the basis of energy. In sheet “Stg Conv & Alloc” of the F-T Jet Fuel Spreadsheet Model, the GHG emissions associated with pumping naturally occurring super critical CO_2 from an underground reservoir in southwest Colorado and transporting this CO_2 to an EOR facility in the Permian Basin of southwest Texas is calculated.

The CO_2e emissions for this activity using Glowing Warming Potential (GWP) values from the International Panel on Climate Change (IPCC) 1996, 2001, and 2007 reports are provided in Table C-3. The displacement calculations were accomplished at the stage level as follows. First, the total GHG emissions for displacement of supercritical CO_2 are stored in the variable SUM_{CO2_disp}. This value is 5.872 g CO_2e/MJ LHV blended jet fuel combusted using the IPCC 2007 GWP. Second, the absolute value of the unallocated GHG emissions for each substage in Stages #1 through #3 was calculated, summed, and stored in the variable $ABSSUM_{unalloc}$. Third,

if the variable $GHG_{unalloc\_x}$ stores the unallocated GHG emissions for substage #x, then the remaining unallocated emissions for substage #x ($GHG_{rem\_unalloc\_x}$) are calculated using the following equation:

$$GHG_{rem\_unalloc\_x} = GHG_{unalloc\_x} - ABS(GHG_{unalloc\_x}) * SUM_{CO2\_disp} / ABSSUM_{unalloc}$$

This equation subtracts a fraction of the total GHG emissions to be displaced (SUM_{CO2_disp}) from the unallocated emissions for each substage in Stages #1 through #3.

Table C-3. CO_2e Emissions Associated with Extraction and Transport of Naturally Occurring CO_2 for EOR

GWP	CO_2e Emissions (kg CO_2e/tonne CO_2 delivered to EOR
IPCC 1996 GWP	70.4
IPCC 2001 GWP	70.6
IPCC 2007 GWP	70.7

Fifth, in energy allocation, the energy content of each remaining co-product stream is determined, the energy contents of all remaining co-product streams are totaled and, for the co-product of interest (F-T jet fuel in this study), the energy content of this stream is divided by the total energy content of all remaining co-product streams. This procedure yields the fraction of the total energy content of all remaining co-product streams that is intrinsic to the co-product of interest. The energy content and density of the remaining F-T co-products are provided in Table 128 of the main report. The mass and energy values of the remaining co-product streams exiting LC Stage #3 are listed in Table C-4 relative to the functional unit of 1 MJ LHV blended jet fuel combusted. Using the energy content of each remaining co-product stream, the percent contribution of each remaining stream is calculated with respect to the total energy content of all of the remaining co-products. F-T jet fuel accounts for 53.1 percent of the total energy of all remaining co-products produced from LC Stage #3 in Scenario 2.

Table C-4. Calculation of Percent Energy Contribution of F-T Jet Fuel with Respect to Total Energy of F-T Jet Fuel, F-T Diesel, and F-T Naphtha (Modified Baseline System Boundary, Scenario 2 Example)

GWP	CO_2e Emissions (kg CO_2e/tonne CO_2 delivered to EOR	CO_2e Emissions (kg CO_2e/tonne CO_2 delivered to EOR	CO_2e Emissions (kg CO_2e/tonne CO_2 delivered to EOR
F-T Jet Fuel (11)	11	0.49	53.1%
F-T Diesel (5)	7.75	0.34	37.1%
F-T Naphtha (6)	2.04	0.09	9.8%
TOTAL:	*20.8*	*0.92*	*100%*

Sixth, the remaining unallocated GHG emissions for the applicable stages are multiplied by the fraction of total energy assigned to the co-product of interest and this becomes the GHG emissions allocated to the co-product of interest. In Scenario 2, the remaining unallocated GHG emissions for LC Stages #1 through #3 ($GHG_{rem\_unalloc\_x}$ for Stage x) are multiplied by the percent energy contribution of F-T jet fuel to yield the CO_2e emissions allocated to F-T jet fuel for LC Stages #1 through #3. The CO_2e emissions for Stages #4 and #5 are calculated separately and added to give the total CO_2e emissions for blended jet fuel. Table C-5 presents the results for the allocation procedure by stage.

Table C-5. Procedure for Allocating GHG Emissions by Percent Energy Contribution of F-T Jet Fuel (Modified Baseline System Boundary, Scenario 2 Example)

Life Cycle Stage	Unit Process	Unallocated Mass of GHG Emitted to Atmosphere (g CO_2e/MJ, LHV Blended Jet Fuel Consumed) (IPCC 2007 GWP)	Remaining Unallocated Mass of GHG Emitted to Atmosphere After Displacement with CO_2 (g CO_2e/MJ, LHV Blended Jet Fuel Consumed) (IPCC 2007 GWP)	% Energy Contribution of F-T Jet Fuel	Allocated Mass of GHG Emitted to Atmosphere (g CO_2e/MJ, LHV Blended Jet Fuel Consumed) (IPCC 2007 GWP)
#1: Raw Material Acquisition	Illinois No. 6 Coal Mining	4.6	3.8	53.1%	2.0
	Switchgrass Production	-15.4	-18.3	53.1%	-9.7
	Land Use Change	1.1	0.87	53.1%	0.46
#2: Raw Material Transport	Rail Transport of Coal	0.81	0.65	53.1%	0.35
	Truck Transport of Switchgrass	0.36	0.29	53.1%	0.16
#3: Liquid Fuels Production	CBTL Plant	8.1	6.6	53.1%	3.5
	Pipeline Transport of CO_2	0.84	0.68	53.1%	0.36
TOTAL:	Stages 1-3	0.43	-5.4	53.1%	-2.9

The GHG emissions from LC Stages #1 through #3 have now been allocated to the F-T jet fuel product and the other co-products removed under the modified baseline system boundary. Although GHG emissions have been allocated to Stages #1 through #3 in this study, it is important to recognize that the “allocated” emissions by unit process or stage do not necessarily represent the actual emissions from a particular unit process or stage associated with a particular product (F-T jet fuel in this instance). For additional discussion of restrictions associated with the interpretation of allocated emissions at the stage or unit process level, please refer to the main body of the report.

The procedures for allocating by volume and mass are similar to the procedure for energy allocation. In volume allocation, the volume of each remaining co-product stream (after the super critical CO_2 co-product stream is eliminated through displacement) is calculated and the fraction of the volume of F-T jet fuel relative to the volume of all remaining co-product streams is used to allocate the GHG emissions for LC Stages #1 through #3. In mass allocation, the mass of each remaining co-product stream is calculated and the fraction of the mass of F-T jet fuel relative to the mass of all remaining co-product streams is used to allocate the GHG emissions for LC Stages #1 through #3.

The energy, volume and mass allocation options allocate the remaining GHG emissions to F-T jet fuel based on the fraction of a physical quantity (energy, volume, mass) for the F-T jet fuel co-product stream relative to the total physical quantity (energy, volume, mass) for all the remaining co-product streams. For a given scenario, the percent assigned to F-T jet fuel is similar whether energy, volume, or mass is used as the basis. Thus, there will be little difference in the results for energy, volume, and mass allocation. Since all the co-products are energy products, the results of only energy allocation (not volume or mass allocation) are presented in the remainder of this appendix, along with the results of displacement allocation.

C.4.2 Calculation Procedure for Displacement Allocation

The allocation procedure for system expansion/displacement was applied to all 10 scenarios. For Scenarios 6-10, the allocation procedure for displacement is the same as for the baseline system boundary because the co-products and system boundary are the same in the modified baseline system boundary and baseline system boundary. For Scenarios 1-5, the allocation procedure for displacement for the modified baseline system boundary is essentially the same as the procedure for the baseline system boundary with two differences. First, in the baseline system boundary, the total unallocated CO_2e emissions are calculated for Stages #1 through #3 including substage #3c (EOR). In the modified baseline system boundary, the CO_2e emissions for substage #3c are not included in the total unallocated CO_2e emissions for Stages #1 through #3. Second, in the baseline system boundary, CO_2e emissions for diesel, naphtha, crude oil and natural gas liquids (22.4 g CO_2e using the IPCC 2007 GWP/MJ LHV blended jet fuel combusted) are displaced from the total unallocated GHG emissions for Stages #1 through #3. In the modified baseline system boundary, CO_2e emissions for diesel, naphtha, and naturally occurring CO_2 (13.4 g CO_2e using the IPCC 2007 GWP/MJ LHV blended jet fuel combusted) are displaced from the total unallocated GHG emissions for Stages 1 through 3.

C.5 Deterministic Allocated Results

Deterministic allocated results for the 10 scenarios are presented in Table C-6 and Table C-7. Energy and displacement allocation were applied for Scenarios 1-10 and the results are presented in these tables. Allocated results are tabulated for each scenario in terms of lifecycle substages in Table C-6**,** and for lifecycle stages and process categories in Table C-7. The results for the baseline system boundary and the modified baseline system boundary are presented in Table C-6 and Table C-7 to allow the two system boundaries to be compared. The results are presented graphically in Figure C-2. This figure is a bar chart which presents the CO_2e emissions for the 10 scenarios and, for each scenario, the CO_2e emissions are provided for the two system boundaries and two allocation methods. The results in Table C-6 and Table C-7 and Figure C-2 use the IPCC 2007 GWP.

The lifecycle results for each applied allocation method are shown in the tables and figure in reference to the conventional jet fuel baseline of 87.4 g CO_2e/MJ, LHV jet fuel combusted.

For all scenarios, the allocated CO_2e emissions for blended jet fuel for the modified baseline system boundary for both allocation methods are below the conventional jet fuel baseline. For Scenario 1 (0 percent switchgrass, iron catalyst, typical production of F-T jet fuel and EOR), the CO_2e emissions for blended jet fuel using displacement allocation for the baseline system boundary exceed the conventional jet fuel baseline (98.2 g CO_2e/MJ, LHV jet fuel combusted for Scenario 1 as compared to 87.4 g CO_2e/MJ, LHV jet fuel combusted for conventional jet fuel). For this same scenario, the CO_2e emissions for blended jet fuel using energy allocation for the baseline system boundary are below the conventional jet fuel baseline CO_2e emissions. For Scenario 5 (14 percent switchgrass, cobalt catalyst, maximize production of F-T jet fuel and EOR), the CO_2e emissions for blended jet fuel using displacement allocation for the baseline system boundary slightly exceed the conventional jet fuel baseline (87.7 g CO_2e/MJ, LHV jet fuel combusted for Scenario 1 as compared to 87.4 g CO_2e/MJ, LHV jet fuel combusted for conventional jet fuel). For Scenario 5, the CO_2e emissions for blended jet fuel using energy allocation for the baseline system boundary are below the conventional jet fuel baseline CO_2e emissions.

For Scenarios 1-5 (the scenarios involving EOR), the CO_2e emissions using energy allocation for the modified baseline system boundary are below the CO_2e emissions using energy allocation for the baseline system boundary. Similarly, the CO_2e emissions using displacement allocation for the modified baseline system boundary are below the CO_2e emissions using displacement.

Energy allocation results in smaller differences in allocated CO_2e emissions across scenarios than does displacement allocation. For the modified baseline system boundary for Scenarios 1-5 using energy allocation, the CO_2e emissions range from 83.6 g CO_2e /MJ, LHV to 67.2 g CO_2e/MJ, LHV. In contrast, for the modified baseline system boundary for Scenarios 1-5 using displacement allocation, the CO_2e emissions range from 80.5 g CO_2e /MJ, LHV to 49.4 g CO_2e/MJ, LHV.

The allocated CO_2e emissions for Scenarios 6-10 are the same for the baseline system boundary and modified baseline system boundary.

Table C-6. Substage Deterministic Allocated Results for 10 Scenarios (g CO_2e/MJ, LHV Jet Fuel Combusted [IPCC 100-Year GWP])

System Boundary and Allocation Method	Total	Stg. 1a:	Stg. 2a:	Stg. 1b:	Stg. 1c:	Stg. 1c:	Stg. 2b:	Stg. 3a:	Stg. 3b:	Stg. 3c:	Stg. 3d:	Stg. 4:			Stg. 5:
		Coal Acq.	Coal Trans.	Biom. Acq.	Dir. Land U	Indir. Land U	Biom. Trans.	CBTL	CO_2 to EOR	EOR	CO_2 Seq.	F-T JF Trans.	Conv. JF	Bl JF Trans.	JF Use
Total CO_2e for Conventional Jet Fuel (Petroleum Baseline)	87.4	6.4	1.3	0.0	0.0	0.0	0.0	5.7	0.0	0.0	0.0	0.0	0.9	0.0	73.1
Scenario 1: 0% SG, Iron F-T Catalyst, Normal Product Slate (Diesel is Produced), EOR															
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	120.6	5.2	0.9	0.0	0.0	0.0	0.0	8.4	0.8	26.7	0.0	0.1	6.9	0.1	71.4
Allocated by Energy	84.9	0.8	0.1	0.0	0.0	0.0	0.0	1.3	0.1	4.1	0.0	0.1	6.9	0.1	71.4
Allocated by Displacement	98.2	2.4	0.4	0.0	0.0	0.0	0.0	3.9	0.4	12.5	0.0	0.1	6.9	0.1	71.4
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	93.9	5.2	0.9	0.0	0.0	0.0	0.0	8.4	0.8	0.0	0.0	0.1	6.9	0.1	71.4
Allocated by Energy	83.6	1.7	0.3	0.0	0.0	0.0	0.0	2.8	0.3	0.0	0.0	0.1	6.9	0.1	71.4
Allocated by Displacement	80.5	0.7	0.1	0.0	0.0	0.0	0.0	1.1	0.1	0.0	0.0	0.1	6.9	0.1	71.4
Scenario 2 (Baseline): 16% SG, Iron F-T Catalyst, Normal Product Slate (Diesel is Produced), EOR															
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	105.6	4.6	0.8	-15.4	-0.4	1.4	0.4	8.1	0.8	26.7	0.0	0.1	6.9	0.1	71.4
Allocated by Energy	82.6	0.7	0.1	-2.3	-0.1	0.2	0.1	1.2	0.1	4.1	0.0	0.1	6.9	0.1	71.4
Allocated by Displacement	83.0	2.8	0.5	-21.3	-0.5	0.9	0.2	4.9	0.5	16.4	0.0	0.1	6.9	0.1	71.4
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	78.9	4.6	0.8	-15.4	-0.4	1.4	0.4	8.1	0.8	0.0	0.0	0.1	6.9	0.1	71.4
Allocated by Energy	75.6	2.0	0.3	-9.7	-0.2	0.6	0.2	3.5	0.4	0.0	0.0	0.1	6.9	0.1	71.4
Allocated by Displacement	65.2	2.6	0.5	-22.0	-0.5	0.8	0.2	4.6	0.5	0.0	0.0	0.1	6.9	0.1	71.4
Scenario 3: 31% SG, Iron F-T Catalyst, Normal Product Slate (Diesel is Produced), EOR															
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	90.0	4.0	0.7	-32.6	-0.7	3.0	0.8	8.7	0.8	26.7	0.0	0.1	6.9	0.1	71.4
Allocated by Energy	80.3	0.6	0.1	-5.0	-0.1	0.5	0.1	1.3	0.1	4.1	0.0	0.1	6.9	0.1	71.4

System Boundary and Allocation Method	Total	Stg. 1a:	Stg. 2a:	Stg. 1b:	Stg. 1c:	Stg. 1c:	Stg. 2b:	Stg. 3a:	Stg. 3b:	Stg. 3c:	Stg. 3d:	Stg. 4:			Stg. 5:
		Coal Acq.	Coal Trans.	Biom. Acq.	Dir. Land U	Indir. Land U	Biom. Trans.	CBTL	CO_2 to EOR	EOR	CO_2 Seq.	F-T JF Trans.	Conv. JF	Bl JF Trans.	JF Use
Allocated by Displacement	67.2	2.9	0.5	-42.1	-1.0	2.1	0.5	6.2	0.6	18.9	0.0	0.1	6.9	0.1	71.4
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	63.3	4.0	0.7	-32.6	-0.7	3.0	0.8	8.7	0.8	0.0	0.0	0.1	6.9	0.1	71.4
Allocated by Energy	67.3	1.9	0.3	-19.3	-0.4	1.4	0.4	4.1	0.4	0.0	0.0	0.1	6.9	0.1	71.4
Allocated by Displacement	49.5	3.0	0.5	-41.3	-1.0	2.2	0.6	6.4	0.6	0.0	0.0	0.1	6.9	0.1	71.4
Scenario 4: 14% SG, Cobalt F-T Catalyst, Normal Product Slate (Diesel is Produced), EOR															
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	105.9	4.5	0.8	-12.5	-0.3	1.2	0.3	8.3	0.8	24.5	0.0	0.1	6.9	0.1	71.3
Allocated by Energy	83.0	0.7	0.1	-2.1	0.0	0.2	0.0	1.4	0.1	4.1	0.0	0.1	6.9	0.1	71.3
Allocated by Displacement	86.1	2.8	0.5	-17.2	-0.4	0.7	0.2	5.2	0.5	15.4	0.0	0.1	6.9	0.1	71.3
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	81.4	4.5	0.8	-12.5	-0.3	1.2	0.3	8.3	0.8	0.0	0.0	0.1	6.9	0.1	71.3
Allocated by Energy	76.9	2.1	0.4	-8.7	-0.2	0.5	0.1	3.9	0.4	0.0	0.0	0.1	6.9	0.1	71.3
Allocated by Displacement	69.8	2.6	0.5	-17.6	-0.4	0.7	0.2	4.9	0.5	0.0	0.0	0.1	6.9	0.1	71.3
Scenario 5: 14% SG, Cobalt F-T Catalyst, Maximize Jet Fuel (No Diesel is Produced), EOR															
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	99.5	3.3	0.6	-9.1	-0.2	0.9	0.2	6.9	0.6	18.0	0.0	0.1	6.9	0.1	71.3
Allocated by Energy	83.2	0.7	0.1	-2.1	0.0	0.2	0.0	1.6	0.1	4.1	0.0	0.1	6.9	0.1	71.3
Allocated by Displacement	87.8	2.3	0.4	-11.8	-0.3	0.6	0.2	4.9	0.4	12.7	0.0	0.1	6.9	0.1	71.3
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	81.5	3.3	0.6	-9.1	-0.2	0.9	0.2	6.9	0.6	0.0	0.0	0.1	6.9	0.1	71.3
Allocated by Energy	77.6	2.1	0.4	-8.7	-0.2	0.6	0.1	4.5	0.4	0.0	0.0	0.1	6.9	0.1	71.3
Allocated by Displacement	75.8	2.4	0.4	-11.5	-0.3	0.6	0.2	5.1	0.4	0.0	0.0	0.1	6.9	0.1	71.3
Scenario 6: 0% SG, Iron F-T Catalyst, Normal Product Slate (Diesel is Produced), Sequestration															
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	93.6	5.2	0.9	0.0	0.0	0.0	0.0	8.4	0.0	0.0	0.5	0.1	6.9	0.1	71.4
Allocated by Energy	86.5	2.8	0.5	0.0	0.0	0.0	0.0	4.5	0.0	0.0	0.3	0.1	6.9	0.1	71.4
Allocated by	86.0	2.6	0.4	0.0	0.0	0.0	0.0	4.2	0.0	0.0	0.3	0.1	6.9	0.1	71.4

System Boundary and Allocation Method	Total	Stg. 1a:	Stg. 2a:	Stg. 1b:	Stg. 1c:	Stg. 1c:	Stg. 2b:	Stg. 3a:	Stg. 3b:	Stg. 3c:	Stg. 3d:	Stg. 4:			Stg. 5:
		Coal Acq.	Coal Trans.	Biom. Acq.	Dir. Land U	Indir. Land U	Biom. Trans.	CBTL	CO_2 to EOR	EOR	CO_2 Seq.	F-T JF Trans.	Conv. JF	Bl JF Trans.	JF Use
Displacement															
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	93.6	5.2	0.9	0.0	0.0	0.0	0.0	8.4	0.0	0.0	0.5	0.1	6.9	0.1	71.4
Allocated by Energy	86.5	2.8	0.5	0.0	0.0	0.0	0.0	4.5	0.0	0.0	0.3	0.1	6.9	0.1	71.4
Allocated by Displacement	86.0	2.6	0.4	0.0	0.0	0.0	0.0	4.2	0.0	0.0	0.3	0.1	6.9	0.1	71.4
Scenario 7: 16% SG, Iron F-T Catalyst, Normal Product Slate (Diesel is Produced), Sequestration															
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	78.6	4.6	0.8	-15.4	-0.4	1.4	0.4	8.1	0.0	0.0	0.5	0.1	6.9	0.1	71.4
Allocated by Energy	78.6	2.5	0.4	-8.2	-0.2	0.8	0.2	4.3	0.0	0.0	0.3	0.1	6.9	0.1	71.4
Allocated by Displacement	70.9	3.5	0.6	-19.1	-0.4	1.1	0.3	6.1	0.0	0.0	0.4	0.1	6.9	0.1	71.4
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	78.6	4.6	0.8	-15.4	-0.4	1.4	0.4	8.1	0.0	0.0	0.5	0.1	6.9	0.1	71.4
Allocated by Energy	78.6	2.5	0.4	-8.2	-0.2	0.8	0.2	4.3	0.0	0.0	0.3	0.1	6.9	0.1	71.4
Allocated by Displacement	70.9	3.5	0.6	-19.1	-0.4	1.1	0.3	6.1	0.0	0.0	0.4	0.1	6.9	0.1	71.4
Scenario 8: 31% SG, Iron F-T Catalyst, Normal Product Slate (Diesel is Produced), Sequestration															
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	63.0	4.0	0.7	-32.6	-0.7	3.0	0.8	8.7	0.0	0.0	0.5	0.1	6.9	0.1	71.4
Allocated by Energy	70.3	2.1	0.4	-17.3	-0.4	1.6	0.4	4.6	0.0	0.0	0.3	0.1	6.9	0.1	71.4
Allocated by Displacement	55.2	3.4	0.6	-37.5	-0.9	2.6	0.6	7.4	0.0	0.0	0.4	0.1	6.9	0.1	71.4
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	63.0	4.0	0.7	-32.6	-0.7	3.0	0.8	8.7	0.0	0.0	0.5	0.1	6.9	0.1	71.4
Allocated by Energy	70.3	2.1	0.4	-17.3	-0.4	1.6	0.4	4.6	0.0	0.0	0.3	0.1	6.9	0.1	71.4
Allocated by Displacement	55.2	3.4	0.6	-37.5	-0.9	2.6	0.6	7.4	0.0	0.0	0.4	0.1	6.9	0.1	71.4
Scenario 9: 14% SG, Cobalt F-T Catalyst, Normal Product Slate (Diesel is Produced), Sequestration															
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	81.1	4.5	0.8	-12.5	-0.3	1.2	0.3	8.3	0.0	0.0	0.5	0.1	6.9	0.1	71.3
Allocated by Energy	80.0	2.6	0.4	-7.3	-0.2	0.7	0.2	4.8	0.0	0.0	0.3	0.1	6.9	0.1	71.3
Allocated by Displacement	75.0	3.5	0.6	-15.2	-0.4	0.9	0.2	6.5	0.0	0.0	0.4	0.1	6.9	0.1	71.3
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	81.1	4.5	0.8	-12.5	-0.3	1.2	0.3	8.3	0.0	0.0	0.5	0.1	6.9	0.1	71.3

System Boundary and Allocation Method	Total	Stg. 1a: Coal Acq.	Stg. 2a: Coal Trans.	Stg. 1b: Biom. Acq.	Stg. 1c: Dir. Land U	Stg. 1c: Indir. Land U	Stg. 2b: Biom. Trans.	Stg. 3a: CBTL	Stg. 3b: CO_2 to EOR	Stg. 3c: EOR	Stg. 3d: CO_2 Seq.	Stg. 4: F-T JF Trans.	Stg. 4: Conv. JF	Stg. 4: Bl JF Trans.	Stg. 5: JF Use
Allocated by Energy	80.0	2.6	0.4	-7.3	-0.2	0.7	0.2	4.8	0.0	0.0	0.3	0.1	6.9	0.1	71.3
Allocated by Displacement	75.0	3.5	0.6	-15.2	-0.4	0.9	0.2	6.5	0.0	0.0	0.4	0.1	6.9	0.1	71.3
Scenario 10: 14% SG, Cobalt F-T Catalyst, Maximize Jet Fuel (No Diesel is Produced), Sequestration															
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	81.2	3.3	0.6	-9.1	-0.2	0.9	0.2	6.9	0.0	0.0	0.4	0.1	6.9	0.1	71.3
Allocated by Energy	80.7	2.6	0.5	-7.3	-0.2	0.7	0.2	5.6	0.0	0.0	0.3	0.1	6.9	0.1	71.3
Allocated by Displacement	79.6	3.0	0.5	-9.8	-0.2	0.8	0.2	6.4	0.0	0.0	0.3	0.1	6.9	0.1	71.3
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)															
Unallocated	81.2	3.3	0.6	-9.1	-0.2	0.9	0.2	6.9	0.0	0.0	0.4	0.1	6.9	0.1	71.3
Allocated by Energy	80.7	2.6	0.5	-7.3	-0.2	0.7	0.2	5.6	0.0	0.0	0.3	0.1	6.9	0.1	71.3
Allocated by Displacement	79.6	3.0	0.5	-9.8	-0.2	0.8	0.2	6.4	0.0	0.0	0.3	0.1	6.9	0.1	71.3

Table C-7. Deterministic Allocated Results for 10 Scenarios (g CO_2e/MJ Jet Fuel Combusted, LHV [IPCC 100-year GWP])

System Boundary and Allocation Method	Total	Results for All Stages						Process Category			
		Stgs. 1-4: Acq. to JF Trans.	Stage 1: Raw Matl. Acq.	Stage 2: Raw Matl. Trans.	Stage 3: JF Prod./ CO_2 Man.	Stage 4: JF Trans.	Stage 5: JF Use	Opera-tion	Construc-tion	Direct Land Use	Indirect Land Use
Total CO_2e for Conventional Jet Fuel (Petroleum Baseline)	87.4	14.3	6.4	1.3	5.7	0.9	73.1	0.0	0.0	0.0	0.0
Scenario 1: 0% SG, Iron F-T Catalyst, Normal Product Slate (Diesel is Produced), EOR											
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	120.6	49.2	5.2	0.9	36.0	7.1	71.4	120.1	0.5	0.0	0.0
Allocated by Energy	84.9	13.5	0.8	0.1	5.5	7.1	71.4	84.8	0.1	0.0	0.0
Allocated by Displacement	98.2	26.8	2.4	0.4	16.8	7.1	71.4	97.9	0.3	0.0	0.0
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	93.9	22.5	5.2	0.9	9.3	7.1	71.4	93.6	0.3	0.0	0.0
Allocated by Energy	83.6	12.1	1.7	0.3	3.0	7.1	71.4	83.4	0.1	0.0	0.0
Allocated by Displacement	80.5	9.0	0.7	0.1	1.2	7.1	71.4	80.4	0.0	0.0	0.0
Scenario 2 (Baseline): 16% SG, Iron F-T Catalyst, Normal Product Slate (Diesel is Produced), EOR											
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	105.6	34.2	-9.7	1.2	35.6	7.1	71.4	103.9	0.6	-0.4	1.4
Allocated by Energy	82.6	11.2	-1.5	0.2	5.4	7.1	71.4	82.4	0.1	-0.1	0.2
Allocated by Displacement	82.9	11.5	-18.1	0.7	21.8	7.1	71.4	82.2	0.4	-0.5	0.9
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	78.9	7.5	-9.7	1.2	8.9	7.1	71.4	77.4	0.4	-0.4	1.4
Allocated by Energy	75.5	4.1	-7.3	0.5	3.8	7.1	71.4	75.0	0.2	-0.2	0.6
Allocated by Displacement	65.2	-6.2	-19.1	0.7	5.1	7.1	71.4	64.6	0.2	-0.5	0.8
Scenario 3: 31% SG, Iron F-T Catalyst, Normal Product Slate (Diesel is Produced), EOR											
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	90.0	18.6	-26.2	1.5	36.3	7.1	71.4	87.0	0.7	-0.7	3.0
Allocated by Energy	80.3	8.8	-4.0	0.2	5.5	7.1	71.4	79.8	0.1	-0.1	0.5
Allocated by Displacement	67.1	-4.3	-38.0	1.0	25.7	7.1	71.4	65.4	0.5	-1.0	2.1
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	63.3	-8.1	-26.2	1.5	9.6	7.1	71.4	60.5	0.5	-0.7	3.0
Allocated by Energy	67.2	-4.2	-16.4	0.7	4.5	7.1	71.4	66.0	0.3	-0.4	1.4

System Boundary and Allocation Method	Total	Results for All Stages						Process Category			
		Stgs. 1-4: Acq. to JF Trans.	Stage 1: Raw Matl. Acq.	Stage 2: Raw Matl. Trans.	Stage 3: JF Prod./ CO_2 Man.	Stage 4: JF Trans.	Stage 5: JF Use	Opera-tion	Construc-tion	Direct Land Use	Indirect Land Use
Allocated by Displacement	49.4	-21.9	-37.1	1.1	7.0	7.1	71.4	47.8	0.4	-1.0	2.2
Scenario 4: 14% SG, Cobalt F-T Catalyst, Normal Product Slate (Diesel is Produced), EOR											
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	105.9	34.5	-7.2	1.1	33.6	7.1	71.3	104.4	0.6	-0.3	1.2
Allocated by Energy	83.0	11.6	-1.2	0.2	5.6	7.1	71.3	82.7	0.1	0.0	0.2
Allocated by Displacement	86.1	14.8	-14.1	0.7	21.1	7.1	71.3	85.4	0.4	-0.4	0.7
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	81.4	10.1	-7.2	1.1	9.1	7.1	71.3	80.1	0.4	-0.3	1.2
Allocated by Energy	76.9	5.6	-6.3	0.5	4.3	7.1	71.3	76.4	0.2	-0.2	0.5
Allocated by Displacement	69.7	-1.6	-14.7	0.6	5.4	7.1	71.3	69.2	0.2	-0.4	0.7
Scenario 5: 14% SG, Cobalt F-T Catalyst, Maximize Jet Fuel (No Diesel is Produced), EOR											
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	99.5	28.1	-5.2	0.8	25.5	7.1	71.3	98.4	0.4	-0.2	0.9
Allocated by Energy	83.2	11.9	-1.2	0.2	5.8	7.1	71.3	83.0	0.1	0.0	0.2
Allocated by Displacement	87.7	16.4	-9.2	0.5	18.0	7.1	71.3	87.1	0.3	-0.3	0.6
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	81.5	10.1	-5.2	0.8	7.5	7.1	71.3	80.5	0.3	-0.2	0.9
Allocated by Energy	77.6	6.3	-6.2	0.5	4.9	7.1	71.3	77.0	0.2	-0.2	0.6
Allocated by Displacement	75.8	4.4	-8.8	0.6	5.5	7.1	71.3	75.2	0.2	-0.3	0.6
Scenario 6: 0% SG, Iron F-T Catalyst, Normal Product Slate (Diesel is Produced), Sequestration											
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	93.6	22.2	5.2	0.9	9.0	7.1	71.4	93.4	0.2	0.0	0.0
Allocated by Energy	86.5	15.1	2.8	0.5	4.8	7.1	71.4	86.4	0.1	0.0	0.0
Allocated by Displacement	86.0	14.6	2.6	0.4	4.5	7.1	71.4	85.9	0.1	0.0	0.0
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	93.6	22.2	5.2	0.9	9.0	7.1	71.4	93.4	0.2	0.0	0.0
Allocated by Energy	86.5	15.1	2.8	0.5	4.8	7.1	71.4	86.4	0.1	0.0	0.0
Allocated by Displacement	86.0	14.6	2.6	0.4	4.5	7.1	71.4	85.9	0.1	0.0	0.0
Scenario 7: 16% SG, Iron F-T Catalyst, Normal Product Slate (Diesel is Produced), Sequestration											
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											

System Boundary and Allocation Method	Total	Results for All Stages						Process Category			
		Stgs. 1-4: Acq. to JF Trans.	Stage 1: Raw Matl. Acq.	Stage 2: Raw Matl. Trans.	Stage 3: JF Prod./ CO_2 Man.	Stage 4: JF Trans.	Stage 5: JF Use	Opera-tion	Construc-tion	Direct Land Use	Indirect Land Use
Unallocated	78.6	7.2	-9.7	1.2	8.6	7.1	71.4	77.3	0.3	-0.4	1.4
Allocated by Energy	78.6	7.1	-5.1	0.6	4.6	7.1	71.4	77.9	0.2	-0.2	0.8
Allocated by Displacement	70.9	-0.5	-15.0	0.9	6.5	7.1	71.4	70.0	0.2	-0.4	1.1
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	78.6	7.2	-9.7	1.2	8.6	7.1	71.4	77.3	0.3	-0.4	1.4
Allocated by Energy	78.6	7.1	-5.1	0.6	4.6	7.1	71.4	77.9	0.2	-0.2	0.8
Allocated by Displacement	70.9	-0.5	-15.0	0.9	6.5	7.1	71.4	70.0	0.2	-0.4	1.1
Scenario 8: 31% SG, Iron F-T Catalyst, Normal Product Slate (Diesel is Produced), Sequestration											
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	63.0	-8.4	-26.2	1.5	9.3	7.1	71.4	60.3	0.4	-0.7	3.0
Allocated by Energy	70.3	-1.1	-13.9	0.8	4.9	7.1	71.4	68.9	0.2	-0.4	1.6
Allocated by Displacement	55.2	-16.2	-32.4	1.2	7.8	7.1	71.4	53.2	0.3	-0.9	2.6
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	63.0	-8.4	-26.2	1.5	9.3	7.1	71.4	60.3	0.4	-0.7	3.0
Allocated by Energy	70.3	-1.1	-13.9	0.8	4.9	7.1	71.4	68.9	0.2	-0.4	1.6
Allocated by Displacement	55.2	-16.2	-32.4	1.2	7.8	7.1	71.4	53.2	0.3	-0.9	2.6
Scenario 9: 14% SG, Cobalt F-T Catalyst, Normal Product Slate (Diesel is Produced), Sequestration											
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	81.1	9.8	-7.2	1.1	8.8	7.1	71.3	80.0	0.3	-0.3	1.2
Allocated by Energy	80.0	8.6	-4.2	0.6	5.1	7.1	71.3	79.3	0.1	-0.2	0.7
Allocated by Displacement	75.0	3.7	-11.1	0.8	6.9	7.1	71.3	74.3	0.2	-0.4	0.9
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	81.1	9.8	-7.2	1.1	8.8	7.1	71.3	80.0	0.3	-0.3	1.2
Allocated by Energy	80.0	8.6	-4.2	0.6	5.1	7.1	71.3	79.3	0.1	-0.2	0.7
Allocated by Displacement	75.0	3.7	-11.1	0.8	6.9	7.1	71.3	74.3	0.2	-0.4	0.9
Scenario 10: 14% SG, Cobalt F-T Catalyst, Maximize Jet Fuel (No Diesel is Produced), Sequestration											
Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	81.2	9.9	-5.2	0.8	7.3	7.1	71.3	80.4	0.2	-0.2	0.9
Allocated by Energy	80.7	9.3	-4.2	0.6	5.9	7.1	71.3	80.0	0.2	-0.2	0.7

System Boundary and Allocation Method	Total	Results for All Stages						Process Category			
		Stgs. 1-4: Acq. to JF Trans.	Stage 1: Raw Matl. Acq.	Stage 2: Raw Matl. Trans.	Stage 3: JF Prod./ CO_2 Man.	Stage 4: JF Trans.	Stage 5: JF Use	Opera-tion	Construc-tion	Direct Land Use	Indirect Land Use
Allocated by Displacement	79.6	8.3	-6.2	0.7	6.7	7.1	71.3	78.9	0.2	-0.2	0.8
Modified Baseline System Boundary—CO_2e Emissions (g CO_2e/MJ LHV)											
Unallocated	81.2	9.9	-5.2	0.8	7.3	7.1	71.3	80.4	0.2	-0.2	0.9
Allocated by Energy	80.7	9.3	-4.2	0.6	5.9	7.1	71.3	80.0	0.2	-0.2	0.7
Allocated by Displacement	79.6	8.3	-6.2	0.7	6.7	7.1	71.3	78.9	0.2	-0.2	0.8

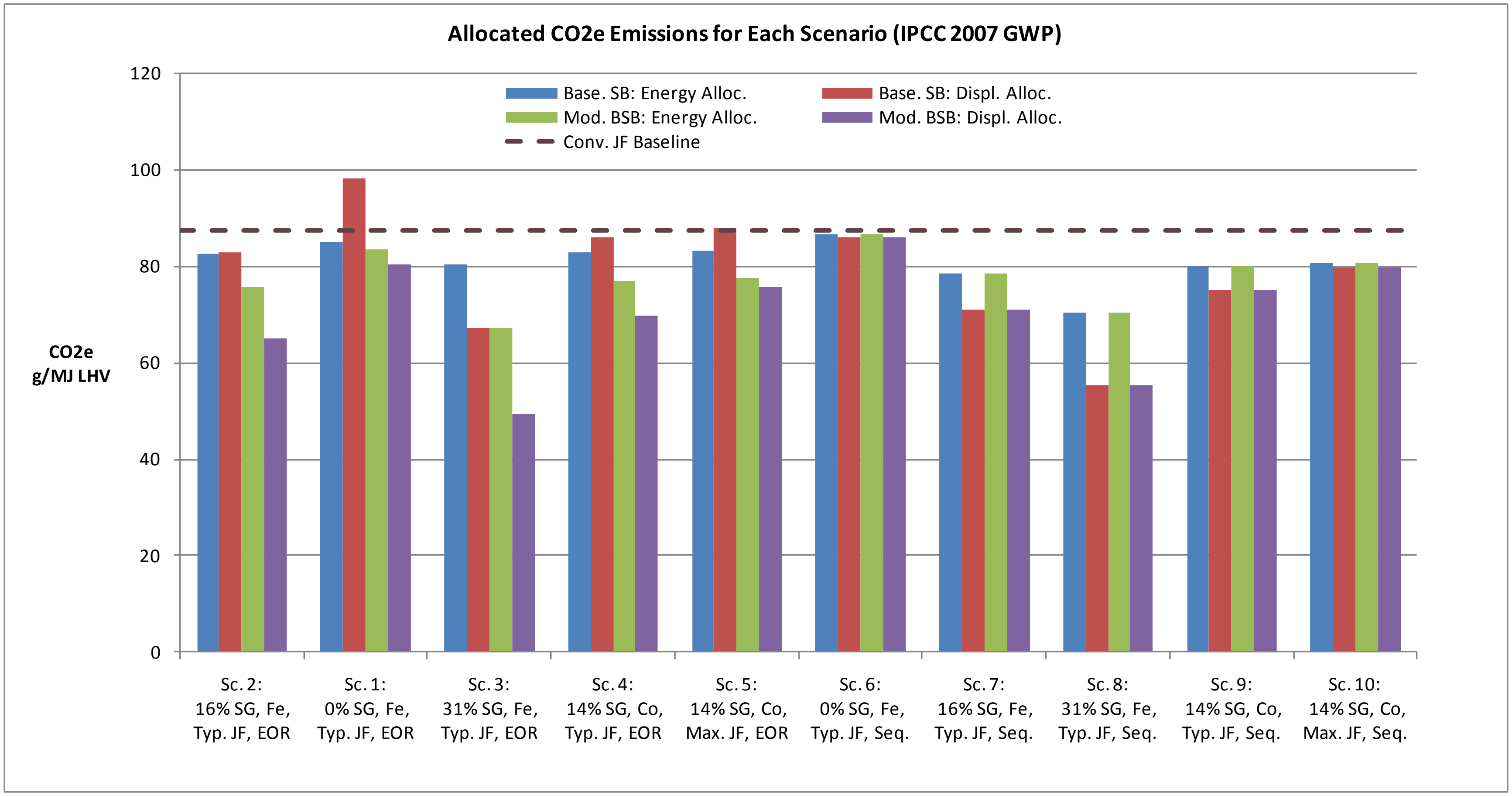


Figure C-2. Allocated CO_2e Emissions for 10 Scenarios (g CO_2e/ MJ, LHV [IPCC 2007 100-year GWP])

LIST OF ACRONYMS, ABBREVIATIONS, AND SYMBOLS

Acronym	Description
AF	Air Force
AFRL	Air Force Research Laboratory
AGT	Acid Gas Treatment
AGR	Acid Gas Removal
ANSI	American National Standards Institute
ARI	Advanced Resources International
ASTM	American Society for Testing and Materials
ASU	Air Separation Unit
bbl/d	Barrel Per Day
Btu	British Thermal Unit
Btu/lb	British Thermal Unit Per Pound
CARB	California Air Resources Board
CBM	Coal Bed Methane
CBTL	Coal and Biomass to Liquids
CH_4	Methane
CRP	Conservation Reserve Program
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COS	Carbonyl Sulfide
DOD	Department of Defense
DOE	Department of Energy
DOT	Department of Transportation
DQI	Data Quality Indicator
DTIC	Defense Technical Information Center
EAR	Export Administration Regulation
EDIP	Environmental Design for Industrial Products
EI	Emissions Indices
EIA	Energy Information Administration
EIOLCA	Economic Input-Output Life Cycle Assessment
EIS	Environmental Impact Study
EISA	Energy Independence and Security Act of 2007
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
ERCOT	Electric Reliability Council of Texas
ERG	Eastern Research Group
FAA	Federal Aviation Agency

LIST OF ACRONYMS, ABBREVIATIONS, AND SYMBOLS *(Cont'd)*

Acronym	Description
F-T	Fischer-Tropsch
gal	Gallon
GREET	Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation Model
GHG	Greenhouse Gas
GWP	Global Warming Potential
h, hr	Hour
H_2	Hydrogen
H_2S	Hydrogen Sulfide
ha	Hectare
HCPV	Hydrocarbon Pore Volume
HFC	Hydrofluorocarbons
HHV	Higher Heating Value
hp, HP	Horsepower
IAWG	Interagency Working Group
IGCC	Integrated Gasification Combined Cycle
IPCC	International Panel on Climate Change
ISO	International Organization for Standardization
ITAR	International Traffic in Arms Regulation
kJ	Kilojoules
kJ/kg	Kilojoules Per Kilogram
kW	Kilowatt
kWe	Kilowatts Electric
kWh	Kilowatt-Hour
lb	Pound
lb/hr	Pounds Per Hour
LC	Life Cycle
LCA	Life Cycle Assessment
LCI	Life Cycle Inventory
LHV	Lower Heating Value
MDEA	Methyldiethanolamine
MJ	Million Joules
MMBtu	Million Metric British Thermal Units (also shown as 10^6 Btu)
MMSCFD	Million Standard Cubic Feet Per Day
MOP	Multi-Output Processes
MPa	Megapascals
MRO	Midwest Reliability Organization

LIST OF ACRONYMS, ABBREVIATIONS, AND SYMBOLS *(Cont'd)*

Acronym	Description
MVA	Monitoring, Verification, and Accounting
MW, MWe	Megawatts Electric
MWth	Megawatts Thermal Energy
N2O	Nitrogen Oxide
N/A	Not Applicable
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
NGL	Natural Gas Liquids
NMVOC	Non-Methane Volatile Organic Compounds
OTAQ	Office of Transportation and Air Quality (of the EPA)
PFC	Perfluorocarbons
pcs	Pieces
PM	Particulate Matter
ppmv	Parts Per Million Volume
PSA	Pressure Swing Adsorption
psia	Pounds Per Square Inch Absolute
psig	Pounds Per Square Inch Gage
RFS	Renewable Fuels Standard (EPA)
SAGE	System for Assessing Aviation's Global Emissions
SBR	Styrene-Butadiene Rubber
SCOT	Shell Claus Off-Gas Treating
SERC	Serc Reliability Corporation
SF_6	Sulfur Hexafluride
SG	Switchgrass
SOM	Soil Organic Matter
SPK	Synthetic Paraffinic Kerosene
ton	Short Ton
tonne	Metric Ton (1000 kg)
t/day	Tonne Per Day
UHC	Unburned Hydrocarbons
US	United States
Volpe	John A. Volpe National Transportation Systems Center (of US DOT)
VRU	Vapor Recovery Unit
WPAFB	Wright-Patterson Air Force Base
WAG	Water Alternating Gas